ASCENT RESOURCES UTICA HOLDINGS, LLC

Consolidated Financial Statements

As of December 31, 2021 and 2020 and for the Years Ended December 31, 2021, 2020 and 2019.

ASCENT RESOURCES UTICA HOLDINGS, LLC

TABLE OF CONTENTS

GLOSSARY OF COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms used in this document:

"2022 Notes." 10.00% senior unsecured notes due 2022.

"2025 Second Lien Term Loans." Second lien term loans due 2025.

"2026 Notes." 7.00% senior unsecured notes due 2026.

"2027 Notes." 9.00% senior unsecured notes due 2027.

"2028 Notes." 8.25% senior unsecured notes due 2028.

"2029 Notes." 5.875% senior unsecured notes due 2029.

"bbl(s)." Barrel(s) as used in reference to crude oil, condensate and NGL. One barrel equals 42 U.S. gallons liquid volume.

"bbls/d." Barrels of crude oil, condensate or NGL per day.

"bbtu." Billion British thermal units.

"bcf." Billion cubic feet of natural gas.

"bcf/d." Billion cubic feet of natural gas per day.

"bcfe." Billion cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"bcfe/d." Billion cubic feet of natural gas equivalent per day.

"btu." British thermal units, a measure of heating value.

"Credit Facility." Our senior secured revolving credit facility.

"Convertible Notes." Convertible notes due 2021.

"DD&A." Depreciation, depletion and amortization expenses.

"exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

"gross." means:

- In relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalty and overriding royalty interests;
- In relation to wells, the total number of wells in which we have an interest before the deduction of outside working interests, royalty interests and overriding royalty interests; and
- In relation to our interest in a property, the total area in acres of properties in which we have an interest.

"mbbls." Thousand barrels of crude oil, condensate or NGL.

"mbbls/d." Thousand barrels of crude oil, condensate or NGL per day.

"mcf." Thousand cubic feet of natural gas.

"mcfe." Thousand cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"mmbtu." Million British thermal units.

"mmbtu/d." Million British thermal units per day.

"mmcf." Million cubic feet of natural gas.

"mmcf/d." Million cubic feet of natural gas per day.

"mmcfe." Million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"mmcfe/d." Million cubic feet of natural gas equivalent per day.

"net." means:

- In relation to our interest in production and reserves, our interest (operating and non-operating) share after the deduction of royalty and overriding royalty interests;
- In relation to wells, the number of wells obtained by aggregating our working interest after the deduction of royalty and overriding royalty interests in each of its gross wells;
- In relation to our interest in a property, the total area in acres in which we have an interest multiplied by our working interest in the area after the deduction of royalty and overriding royalty interests; and
- In relation to our interest in leasehold acreage, our gross working interest after the deduction of royalty and overriding royalty interests.

"NGL." Natural gas liquids.

"NYMEX." The New York Mercantile Exchange.

"operator." The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

"proved developed non-producing." Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market accessibility or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

"proved developed producing." Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

"proved reserves." Defined by the SEC as the quantities of natural gas, oil and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations.

"proved undeveloped." or *"PUD(s)."* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"PV-10." Pre-tax present value of estimated future natural gas, oil and NGL revenues, net of estimated direct expenses, discounted at an annual discount rate of 10%.

"reserves." Estimated remaining quantities of natural gas and oil and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"royalty interest." An interest in a natural gas and oil lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage.

"Senior Notes." The 2022 Notes, 2026 Notes, 2027 Notes, 2028 Notes and 2029 Notes.

"standardized measure." The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved natural gas and oil reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for the consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rates with consideration of

future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved natural gas and oil reserves. However, we are a disregarded entity for income tax purposes and therefore do not estimate future income tax expense.

"tcfe." Trillion cubic feet equivalent, with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"*unproved properties."* Properties with no proved reserves.

"working interest." An interest in a natural gas and oil lease that gives the owners of the interest the right to drill for and produce natural gas, oil and NGL on the leased acreage and requires the owners of the interest to pay their share of the costs of drilling, completions and production operations.

"WTI." West Texas Intermediate.

Business Overview

Unless otherwise indicated or the context otherwise requires, references to "we," "our" and "us" refer to Ascent Resources Utica Holdings, LLC together with its wholly-owned subsidiaries.

We are one of the largest private producers of natural gas in the United States and are focused on acquiring, developing, producing and operating natural gas and oil properties located in the Utica Shale. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (our "Member") and an indirect wholly-owned subsidiary of Ascent Resources, LLC (our "Parent"). We were formed in 2013 by our private equity sponsors, primarily The Energy & Minerals Group and First Reserve Corporation, to utilize our technical expertise to acquire and exploit assets in the Utica Shale. Our asset base is concentrated in southern Ohio, where we target primarily the Point Pleasant interval of the Utica Shale, one of the premier North American shale plays. Our largely contiguous development footprint of approximately 337,000 net leasehold acres, including 73,000 mineral acres, lies within the core of the southern Utica Shale and, as supported by our drilling results and those of offset operators, offers development opportunities with predictable and repeatable production profiles, low breakeven costs and industry-leading rates of return. We also own royalty interests in approximately 5,700 mineral acres that are being developed by third-party operators and provide enhanced value without additional capital costs or operating expenses.

We are continuously focused on enhancing our drilling and completion techniques, minimizing costs and maximizing the ultimate recovery of natural gas, oil and NGL from our assets, with the goal of generating top-tier corporate-level returns and sustainable free cash flow in a capital efficient and financially disciplined manner.

2021 Highlights

Significant financial and operating results for the year ended December 31, 2021 include:

- In June 2021, we issued $400.0 million in aggregate principal amount of 2029 Notes. The net proceeds were used to repay a portion of the borrowings outstanding under our Credit Facility.
- We redeemed the remaining $68.0 million in aggregate principal amount of 2022 Notes on April 1, 2021 for $71.4 million, plus accrued and unpaid interest.
- The remaining $8.3 million in aggregate principal amount of Convertible Notes matured on March 1, 2021 and was redeemed for $12.8 million, plus accrued and unpaid interest.
- Our liquidity as of December 31, 2021 was $1.19 billion, comprised of $1.19 billion of available borrowing capacity under our Credit Facility and a cash balance of $5.7 million.
- Our net daily production for the year ended December 31, 2021 averaged 1.94 bcfe/d and was comprised of approximately 91% natural gas, 3% oil and 6% NGL.
- We spud 72 wells, hydraulically fractured 72 wells and turned-in-line 72 new wells.
- Our average realized price for the year ended December 31, 2021, including the effects of settled derivatives, increased 10% to $2.99 per mcfe from $2.71 per mcfe for the year ended December 31, 2020.

COVID-19 and Market Update

We continue to monitor the current and potential impacts of the novel coronavirus ("COVID-19") pandemic on all aspects of our business, including how it has impacted, and may in the future impact, our operations, financial results, liquidity, employees and communities in which we operate. We also continue to monitor a number of factors that may cause actual results of operations to differ from our historical results or current expectations.

Throughout the second half of 2021 and into 2022, the effects of COVID-19 mitigation efforts, including the wide availability of vaccines, the relaxation of COVID-19 related restrictions and optimism regarding economic recovery have contributed to increased demand and prices for oil, natural gas and NGL. However, there remains uncertainty around the ultimate severity, scope and duration of the pandemic, vaccine administration rates and efficacy, potential resurgences of COVID-19 cases and the emergence of new, more contagious or vaccine-resistant virus variants and the direction or extent of current or future restrictive actions that may be imposed by governments or public health authorities. In addition, the economy is experiencing elevated inflation levels as a result of global supply and demand imbalances resulting from COVID-19. The United States Bureau of Labor Statistics consumer price index for all urban consumers increased 7% from December 31, 2020 to December 31, 2021 as compared to the average historical 10-year rate of approximately 2%. Additionally, unemployment rates continue to improve as demonstrated by declines from a high of approximately 15% in April 2020 to approximately 4% in December 2021 which could lead to potential labor shortages. Inflationary pressures and labor shortages could result in increases to our capital and operating expenses that are not fixed and could impact the renegotiation of certain contracts, among other things. Furthermore, commodity markets are currently also subject to heightened levels of uncertainty related to the Russian military incursion into Ukraine, which could give rise to regional instability and result in heightened economic sanctions by the U.S. and the international community that, in turn, could increase uncertainty with respect to global financial markets and production output from the Organization of Petroleum Exporting Countries and other oil producing nations. As the full impact of COVID-19 and the volatility in commodity prices continues to evolve, we cannot be certain as to the full magnitude they will have on our future financial condition, liquidity, results of operations or cash flows.

Properties

Well Data

As of December 31, 2021, we held an interest in 1,010 gross (614 net) productive wells, including 862 gross (614 net) properties in which we held a working interest and 148 gross properties in which we only held an overriding or royalty interest. Of the wells in which we had a working interest, 817 gross (589 net) were classified as productive natural gas wells and 45 gross (25 net) were classified as productive oil wells. We operated approximately 670 gross (597 net) of our productive wells in which we had a working interest. During 2021, we drilled 72 gross (69 net) wells as operator and participated in two gross wells and held an overriding or royalty interest in another seven gross wells drilled by other operators. We operated approximately 99% of our net production volumes in 2021.

Drilling Activity

The following table describes the productive wells we operated or participated in during the periods indicated:

	Productive Wells Drilled during the Year Ended December 31,					
	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development	74	69	78	73	128	112

As of December 31, 2021, we had 45 gross (41 net) wells in the process of drilling, completing or turning-in-line. We did not drill any exploratory or dry development wells during the years ended December 31, 2021, 2020 or 2019.

Acreage

The following tables set forth information as of December 31, 2021 related to our leasehold acreage position. Developed acreage is acreage spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional working interests owned in gross acres equals one.

The following table sets forth our gross and net acres of developed and undeveloped natural gas and oil leasehold as of December 31, 2021:

Developed Acres		Undeveloped Acres		Total Acres	
Gross	Net	Gross	Net[(a)]	Gross	Net[(b)]
188,456	151,253	212,679	185,285	401,135	336,538

(a) Approximately 64% of our net undeveloped leasehold acreage is not subject to expiration because it is held by production, or it is acreage on which we own the mineral rights.

(b) We own royalty interests in approximately 78,700 mineral acres, including 5,700 mineral acres where development is controlled by third-party operators.

The following table sets forth the number of total undeveloped acres as of December 31, 2021 that will expire unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed:

	Acres Subject to Expiration	
	Gross	Net
2022	31,251	29,766
2023	16,422	15,207
2024	12,132	11,791
2025	2,369	2,283
2026 and thereafter	7,190	7,144
Total	69,364	66,191

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell natural gas and ethane. We believe we will have sufficient production quantities and firm transportation capacity to meet substantially all of such commitments; however, we may be required to purchase natural gas or ethane from third parties to satisfy shortfalls should they occur. The following table includes our firm sales commitments as of December 31, 2021:

	Natural Gas (bbtu)	Ethane (mbbls)
2022	104,781	1,152
2023	104,781	962
2024	62,363	965
2025	46,746	962
2026	46,746	962
2027 - 2029	105,143	2,890
Total	470,560	7,893

Production Volumes, Sales Prices, Lease Operating Expenses and Gathering, Processing and Transportation Expenses

The following table sets forth information regarding our net production volumes, average sales prices received, lease operating expenses and gathering, processing and transportation expenses for the periods indicated:

	Year Ended December 31,		
	2021	2020	2019
Net Production Volumes:			
Natural gas (mmcf)	645,752	646,982	638,243
Oil (mbbls)	3,110	4,291	4,794
NGL (mbbls)	7,012	9,304	8,685
Natural Gas Equivalent (mmcfe)	706,484	728,553	719,113
Average Sales Prices:			
Natural gas ($/mcf)	$ 3.89	$ 1.95	$ 2.49
Oil ($/bbl)	$ 60.47	$ 32.33	$ 50.38
NGL ($/bbl)	$ 34.47	$ 12.71	$ 17.11
Natural Gas Equivalent ($/mcfe)	$ 4.16	$ 2.08	$ 2.75
Settlements of commodity derivatives ($/mcfe)	(1.17)	0.63	0.27
Average sales price, after effects of settled derivatives ($/mcfe)	$ 2.99	$ 2.71	$ 3.02
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.13	$ 0.11	$ 0.10
Gathering, processing and transportation expenses	$ 1.33	$ 1.26	$ 1.19

Natural Gas, Oil and NGL Reserves

All of our estimated reserves are located within the Point Pleasant interval of the Utica Shale. The following table sets forth our proved reserves as of December 31, 2021:

	December 31, 2021			
	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)
Proved developed reserves[(a)]	4,493,267	14,587	51,594	4,890,355
Proved undeveloped reserves	3,716,459	33,124	72,488	4,350,132
Total	8,209,726	47,712	124,082	9,240,487

(a) Approximately 87.5 bcfe, or 2%, of our proved developed reserves were proved developed non-producing.

The table below sets forth information as of December 31, 2021, with respect to our estimated proved reserves, the associated estimated future net revenue, PV-10 and the standardized measure of discounted cash flows. Neither the estimated future net revenue, PV-10 nor the standardized measure is intended to represent the current market value of the estimated natural gas, oil and NGL reserves we own. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs under existing economic conditions as of December 31, 2021. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2021. The average adjusted prices used in our reserve reports were $3.56 per mcf of natural gas, $59.39 per bbl of oil and $31.89 per bbl of NGL utilizing a benchmark of $3.60 per mmbtu of natural gas and $66.55 per bbl of oil and condensate. These prices should not be interpreted as a prediction of future prices, nor do they reflect the prices used to value our commodity derivative instruments in place as of December 31, 2021. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to DD&A. PV-10 is a non-GAAP measure that typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense. However, because we are a disregarded entity for income tax purposes, we have estimated no future income tax expense, and the two measures are the same as of December 31, 2021.

	December 31, 2021		
($ in thousands)	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$ 10,111,899	$ 8,960,627	$ 19,072,525
PV-10	$ 5,020,129	$ 4,115,430	$ 9,135,560
Standardized measure[a]			$ 9,135,560

(a) See Note 12, *Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves*, of the notes to our consolidated financial statements included in this report for further discussion.

As of December 31, 2021, our estimated proved reserves included approximately 4.350 tcfe of reserves classified as proved undeveloped, compared to approximately 4.715 tcfe as of December 31, 2020. The table below is a summary of changes in our PUDs for 2021:

	Total (mmcfe)
Proved undeveloped reserves at December 31, 2020	4,715,327
Extensions, discoveries and other additions	656,726
Revisions	32,115
Conversions into proved developed reserves	(1,054,036)
Proved undeveloped reserves at December 31, 2021	4,350,132

Our proved undeveloped extensions and discoveries of approximately 656.7 bcfe of reserves resulted from the continued development of our Utica Shale acreage. Revisions of previous PUD estimates included upward revisions of 199.2 bcfe primarily due to development plan optimization and 66.8 bcfe due to SEC pricing improvements, and downward revisions of 233.9 bcfe due to the removal of PUDs where it was determined development would occur outside of our five-year development plan, net of additions of previously proved locations that were added to our five-year development plan. As of December 31, 2021, there were no PUDs that had remained undeveloped for five years or more. In 2021, we invested $392.2 million to convert 1.054 tcfe from proved undeveloped reserves to proved developed reserves.

The future net revenues attributable to our estimated PUDs of $9.0 billion as of December 31, 2021, and associated PV-10 of $4.1 billion, have been calculated assuming that we will expend approximately $1.7 billion to develop these reserves over the next five years, although the amount and timing of these expenditures will depend on a number of factors, including, but not limited to, actual drilling results, service costs, commodity prices and the availability of capital. Our developmental drilling schedule is subject to revision and reprioritization throughout the year resulting from unpredictable factors such as unexpected drilling results, title issues and infrastructure availability or constraints.

Evaluation and Review of Reserves

The estimation of our proved reserves is prepared internally by our staff of petroleum engineers and geoscience professionals. Our Senior Vice President of Exploration and Resource Development is the technical person primarily responsible for overseeing the preparation of all of our reserve estimates. He holds a Bachelor of Science degree in Chemical Engineering from the University of Oklahoma. Before joining Ascent, he held various technical and managerial positions with Chesapeake Energy Corporation, ARCO, Phillips Petroleum and ConocoPhillips and has more than 24 years of reservoir estimation and operations experience.

The preparation of our historical proved reserve estimates is completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- Verification of property ownership by our land department;
- Verification of various state severance and ad valorem tax rates by our tax department;
- Review and verification of historical production data, which data is based on actual production as reported by us;
- Review and verification of historical lease operating expenses, which data is based on actual accounting data as reported by us;
- Review and verification of historical capital expenditures, which data is based on actual accounting data as reported by us;

- Review and verification of historical realized pricing differentials and marketing contract fees, which data is based on actual accounting data as reported by us;
- Review of our proved undeveloped wells to ensure that the timing and future rates of production are consistent with current development plans and our financial ability to develop such reserves within five years;
- Review of reserve estimates by our Senior Vice President of Exploration and Resource Development or under his direct supervision; and
- Review by our Chief Executive Officer, Chief Financial Officer and Chief Operating Officer of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new PUD additions.

We engaged the services of Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm, to audit the 2021 reserves estimated by our petroleum engineering staff. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and represented 100% of our proved reserves and 100% of the present value of our proved reserves discounted at 10%. The technical persons at NSAI primarily responsible for auditing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Additionally, our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. Our internal technical team members meet with our independent reserve engineers periodically during the preparation of the reserve reports to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information for our properties, such as ownership interest, natural gas, oil and NGL production, well test data, commodity prices and operating and development costs. Any differences found in the analysis of the estimation of our proved reserves by our independent reserve engineers are reviewed with our Senior Vice President of Exploration and Resource Development. Our estimates of proved reserves and the present value of such reserves, discounted at 10%, did not differ from the estimates of our independent reserve engineers by more than the recommended threshold of 10% set forth in the SPE Standards.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Our Management's Discussion and Analysis of our Financial Condition and Results of Operations ("MD&A") should be read in conjunction with our consolidated financial statements and related notes, included herein. The following discussion and analysis contains forward-looking statements that involve known and unknown risks, uncertainties and assumptions. The forward-looking statements are not historical facts, but rather reflect our future plans, estimates, beliefs and expected performance. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Results of Operations

Year Ended December 31, 2021 Compared to 2020

Revenues. The following table sets forth certain information for the periods indicated regarding our revenues, average sales prices received and net production volumes:

	Year Ended December 31,		Variance	
	2021	2020	Amount	Percent
Revenues ($ in thousands):				
Natural gas	$ 2,510,150	$ 1,258,594	$ 1,251,556	99 %
Oil	188,076	138,723	49,353	36 %
NGL	241,731	118,224	123,507	104 %
Total Revenues, before effects of commodity derivatives	$ 2,939,957	$ 1,515,541	$ 1,424,416	94 %
Average Sales Prices:				
Natural gas ($/mcf)	$ 3.89	$ 1.95	$ 1.94	99 %
Oil ($/bbl)	$ 60.47	$ 32.33	$ 28.14	87 %
NGL ($/bbl)	$ 34.47	$ 12.71	$ 21.76	171 %
Natural Gas Equivalent ($/mcfe)	$ 4.16	$ 2.08	$ 2.08	100 %
Settlements of commodity derivatives ($/mcfe)	(1.17)	0.63	(1.80)	(286)%
Average sales price, after effects of settled derivatives ($/mcfe)	$ 2.99	$ 2.71	$ 0.28	10 %
Net Production Volumes:				
Natural gas (mmcf)	645,752	646,982	(1,230)	— %
Oil (mbbls)	3,110	4,291	(1,181)	(28)%
NGL (mbbls)	7,012	9,304	(2,292)	(25)%
Natural Gas Equivalent (mmcfe)	706,484	728,553	(22,069)	(3)%
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,769	1,768	1	— %
Oil (mbbls/d)	9	12	(3)	(25)%
NGL (mbbls/d)	19	25	(6)	(24)%
Natural Gas Equivalent (mmcfe/d)	1,936	1,991	(55)	(3)%

The $1.42 billion increase in natural gas, oil and NGL revenues (excluding the effects of derivatives) was primarily due to a 100% increase in our average sales price per mcfe, which was partially offset by a 3% decline in total production volumes. Commodity prices fluctuate in response to changes in supply and demand, market uncertainty and a variety of other factors beyond our control.

A change in commodity prices has a direct impact on our sales and cash flows. The following table illustrates the effects of an increase or decrease in commodity prices on our sales and cash flows, before the effects of derivatives, assuming our production levels for the year ended December 31, 2021 remained constant:

($ in thousands)	Volumes	Price Fluctuation per Unit	Effect on Sales and Cash Flows
Commodity:			
Natural Gas (mmcf)	645,752	$ 0.10	$ 64,575
Oil (mbbls)	3,110	$ 1.00	$ 3,110
NGL (mbbls)	7,012	$ 1.00	$ 7,012

Impact of Commodity Derivative Instruments. We use commodity derivative instruments to mitigate our exposure to fluctuations in future commodity prices in order to protect our anticipated operating cash flow against significant market movements or volatility. The following table sets forth the settlements of our derivative instruments and the change in fair value for the periods indicated:

	Year Ended December 31,	
($ in thousands)	2021	2020
Net Settlements of Commodity Derivatives:		
Natural Gas	$ (773,209)	$ 402,391
Oil	(24,612)	48,273
NGL	(25,695)	5,196
Total Net Settlements of Commodity Derivatives	(823,516)	455,860
Change in Fair Value of Commodity Derivatives:		
Natural Gas	(871,023)	(472,299)
Oil	(30,690)	4,252
NGL	(18,663)	(6,980)
Total Change in Fair Value of Commodity Derivatives	(920,376)	(475,027)
Total Loss on Commodity Derivatives	$ (1,743,892)	$ (19,167)

Operating Expenses. The following table sets forth our operating expenses and costs per mcfe:

	Year Ended December 31,		Variance	
	2021	2020	Amount	Percent
Operating Expenses ($ in thousands):				
Lease operating expenses	$ 90,719	$ 77,521	$ 13,198	17 %
Gathering, processing and transportation expenses	$ 936,134	$ 919,986	$ 16,148	2 %
Taxes other than income	$ 38,988	$ 37,495	$ 1,493	4 %
Exploration expenses	$ 83,367	$ 104,230	$ (20,863)	(20)%
General and administrative expenses	$ 58,334	$ 63,825	$ (5,491)	(9)%
Natural gas and oil depreciation, depletion and amortization	$ 595,481	$ 733,450	$ (137,969)	(19)%
Depreciation and amortization of other assets	$ 2,926	$ 4,267	$ (1,341)	(31)%
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.13	$ 0.11	$ 0.02	18 %
Gathering, processing and transportation expenses	$ 1.33	$ 1.26	$ 0.07	6 %
Taxes other than income	$ 0.06	$ 0.05	$ 0.01	20 %
General and administrative expenses	$ 0.08	$ 0.09	$ (0.01)	(11)%
Natural gas and oil depreciation, depletion and amortization	$ 0.84	$ 1.01	$ (0.17)	(17)%

- Lease operating expenses per mcfe increased as a result of an increase in our total number of producing wells, combined with an increase in compression costs and a reduction in our overall production during 2021 compared to 2020.

- Gathering, processing and transportation expenses per mcfe increased primarily as a result of an increase in gathering and firm transportation rates and a decrease in production during 2021 compared to 2020.
- Exploration expense was primarily driven by impairments of $79.0 million and $100.2 million in 2021 and 2020, respectively, for unproved natural gas and oil properties for which the leases are expected to expire. As we continue to review our acreage position and high grade our drilling inventory, focusing on our core type curve areas, additional leasehold impairments and abandonments may be recorded.
- General and administrative expenses decreased primarily due to $5.6 million of accrued non-recurring legal expenses recorded during 2020.
- Natural gas and oil DD&A per mcfe decreased primarily due to increased capital efficiencies, resulting in lower well costs in 2021 compared to 2020.

Interest Expense. Interest expense was $174.8 million and $134.3 million in 2021 and 2020, respectively, detailed as follows along with our weighted average debt outstanding:

	Year Ended December 31,	
($ in thousands)	2021	2020
Credit Facility	$ 30,652	$ 45,969
2025 Second Lien Term Loans	55,851	12,219
Senior Notes	112,756	124,643
Convertible Notes	93	4,026
Loss on interest rate derivatives	267	790
Amortization of debt discounts, premium and issuance costs	18,639	25,186
Other	5,040	3,634
Capitalized interest	(48,458)	(82,208)
Total Interest Expense, net	$ 174,840	$ 134,259
Weighted Average Debt Outstanding:		
Credit Facility	$ 879,855	$ 1,230,855
2025 Second Lien Term Loans	549,822	120,180
Senior Notes	1,485,333	1,434,977
Convertible Notes	1,343	61,744
Weighted Average Debt Outstanding	$ 2,916,353	$ 2,847,756

The increase in interest expense in 2021 compared to 2020 was primarily due to reduced capitalized interest resulting from changes in our development activities.

Losses on Purchases or Exchanges of Debt. We recognized a net loss of $3.8 million on purchases or exchanges of debt in 2021 primarily due to us repurchasing the remaining outstanding principal of our 2022 Notes. We recognized a net loss of $6.0 million on purchases or exchanges of debt in 2020 primarily due to $17.7 million of fees related to the Exchange (defined below) of 2022 Notes. We also recognized a $2.7 million loss on the repurchase of a portion of our Convertible Notes in 2020. This was partially offset by our repurchase of a portion of our 2022 Notes, which resulted in a $14.3 million gain. See Note 4, *Senior Notes* and *Convertible Notes*, of the notes to our consolidated financial statements included in this report for further discussion of our repurchases and exchanges of debt.

Year Ended December 31, 2020 Compared to 2019

The comparison of our results of operations for the years ended December 31, 2020 to 2019 can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our prior year financial statements, which are available on our website.

Liquidity and Capital Resources

Overview

The drilling, completion and production of our natural gas and oil properties are capital intensive activities that require access to significant capital. We continually evaluate our capital needs and compare them to our capital resources. Our primary sources of funds are internally generated cash flows from operations, draws on our Credit Facility and proceeds from the issuance of debt, and historically have included equity contributions from our Parent. Our future success in growing our proved reserves and production will be highly dependent upon net cash provided by our operating activities and the capital resources available to us. Based on existing market conditions and our expected liquidity needs, among other factors, we intend to use a portion of our cash flows from operations to repay or redeem portions of our indebtedness. Additionally, we may use securities offerings or other debt issuances to repay debt prior to scheduled maturities, and we may seek opportunities to refinance all or a portion of our indebtedness, including through cash purchases, exchanges, open market purchases, privately negotiated transactions or otherwise, as demonstrated through our recent debt transactions. See Note 4 of the notes to our consolidated financial statements included in this report for further discussion of our recent debt transactions.

Our cash flow from operating activities is highly dependent upon our ability to produce and sell our natural gas, oil and NGL production and the sales prices that we receive. Commodity prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we realize for our production is also impacted by our commodity hedging activities. Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. Although we are continually securing additional derivative positions for portions of our expected future production, there can be no assurance that we will be able to add derivative positions to cover the remainder of our expected production at favorable prices. See Quantitative and Qualitative Disclosures about Market Risk and Note 5 of our consolidated financial statements included in this report for further details.

As of December 31, 2021, we had a cash balance of $5.7 million and availability under our Credit Facility of $1.19 billion. In November 2021, the borrowing base under the Credit Facility was reaffirmed at $1.85 billion. Based on our expected operating cash flows, Credit Facility availability and cash on hand, we anticipate being able to satisfy all of our financial obligations and liquidity needs for the next twelve months.

Long-term cash flows are subject to a number of variables including our level of production and prices as well as various economic conditions that have historically affected the natural gas and oil industry. Based on our significant borrowing capacity under our Credit Facility with a maturity date in 2024, commodity derivatives we have in place which cover a portion of our expected annual production through 2024 and having no significant maturities of senior notes or term loans until 2025 and beyond, we believe we will have adequate capital resources and liquidity for the foreseeable future.

We establish a capital budget at the beginning of each calendar year and periodically review or adjust our allocation for capital expenditures as business conditions warrant. Actual capital expenditures may vary due to many factors, including drilling results, commodity prices, industry conditions, the prices and availability of goods and services, inflationary pressure and the extent to which properties are acquired or assets are sold. Our 2022 capital budget is approximately $710 million to $770 million, and we expect to operate an average of 3 to 4 rigs and to turn-in-line between 75 and 80 wells. We currently plan to fund our 2022 capital program through cash on hand, expected cash flow from our operations and borrowings under our Credit Facility.

Sources and Uses of Funds

The following table presents the sources of cash and cash equivalents:

	Year Ended December 31,		
($ in thousands)	**2021**	**2020**	**2019**
Cash provided by operating activities	$ 760,637	$ 773,836	$ 1,140,674
Proceeds from issuance of long-term debt	400,000	300,000	—
Proceeds from the Exchange	—	20,000	—
Proceeds from divestitures of natural gas and oil properties	—	—	12,474
Proceeds from Credit Facility borrowings, net of repayments	—	—	240,000
Financing commodity derivative settlements	—	1,557	—
Total Sources of Cash and Cash Equivalents	$ 1,160,637	$ 1,095,393	$ 1,393,148

Our primary source of funds is net cash flow provided by operating activities, which was approximately $760.6 million, $773.8 million and $1.14 billion for 2021, 2020 and 2019, respectively. Operating cash flows in 2021 compared to 2020 were positively impacted by a year over year increase in prices received for commodity sales, which was more than offset by an increase in cash settlements paid to our counterparties on commodity derivatives and year-end timing differences between the settlements of our commodity derivatives and the receipt of sales associated with the produced volumes.

In June 2021, we issued $400.0 million in aggregate principal amount of 2029 Notes. In December 2020, we issued $300.0 million in aggregate principal amount of 2028 Notes. In October 2020, we issued $537.8 million in aggregate principal amount of 2025 Second Lien Term Loans and $339.7 million in aggregate principal amount of 2027 Notes in exchange for $856.7 million of aggregate principal amount of 2022 Notes ('the "Exchange"). In connection with the Exchange, we issued an additional $12.0 million in aggregate principal amount of 2025 Second Lien Term Loans, $8.6 million in aggregate principal amount of 2027 Notes and equity of our Parent to certain existing equity holders and their designated affiliates in exchange for an aggregate contribution of $20.0 million in cash.

The following table presents the uses of cash and cash equivalents:

($ in thousands)	Year Ended December 31, 2021	2020	2019
Natural Gas and Oil Expenditures:			
Drilling and completion costs	$ 496,565	$ 557,656	$ 1,096,627
Acquisitions of natural gas and oil properties	52,648	71,102	163,220
Interest capitalized[(a)]	48,458	82,208	123,370
Total Natural Gas and Oil Expenditures	597,671	710,966	1,383,217
Other Uses of Cash and Cash Equivalents:			
Repayment of Credit Facility, net of borrowings	458,000	235,000	—
Repayment of long-term debt	84,173	138,764	—
Additions to other property and equipment	1,444	1,509	3,547
Cash paid for debt issuance costs	7,229	6,842	9,512
Financing commodity derivative settlements	11,188	—	—
Other	4,101	815	556
Total Other	566,135	382,930	13,615
Total Uses of Cash and Cash Equivalents	$ 1,163,806	$ 1,093,896	$ 1,396,832

(a) Interest is capitalized on significant investments in active unproved properties and wells in process.

Our cash drilling and completion costs were $496.6 million, $557.7 million and $1.10 billion in 2021, 2020 and 2019, respectively. The decrease in drilling and completion costs in 2021 was the result of us completing and turning-in-line fewer wells as well as reduced costs per lateral foot due to increased completion stages per day and improved drilling cycle times. We drilled 72 new wells in 2021 compared to 75 new wells in 2020 and 126 new wells in 2019. We spent cash of $52.6 million, $71.1 million and $163.2 million in 2021, 2020 and 2019, respectively, primarily related to the acquisition of leases arising in the ordinary course of business.

We spent cash of $84.2 million in 2021 to redeem $68.0 million in aggregate principal amount of our 2022 Notes at 105.00% of the outstanding principal value, plus accrued and unpaid interest, and $8.3 million in aggregate principal amount of our Convertible Notes at 153.8% of the outstanding principal value, plus accrued and unpaid interest. In 2020, we spent cash of $138.8 million to repurchase $50.3 million in aggregate principal amount of our 2022 Notes, plus accrued and unpaid interest, and $69.0 million in aggregate principal amount of our Convertible Notes, plus accrued and unpaid interest.

Certain Indebtedness

Credit Facility

Our Credit Facility matures on April 1, 2024, and as of December 31, 2021, it had a fully committed borrowing base of $1.85 billion, of which $250.0 million was authorized for letters of credit. The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about May 1 and November 1 of each year primarily based on the estimated value and future net cash flows of our proved natural gas, oil and NGL reserves and our commodity derivative positions, as determined by lenders under the Credit Facility at their discretion. If the commodity price environment declines over an extended period, it may in the future lead to a reduction in the borrowing base of our Credit Facility. We do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations. As of December 31, 2021, we had $495.0 million of borrowings outstanding and $169.2 million of letters of credit issued under the Credit Facility.

As of December 31, 2021, we were in compliance with all applicable financial covenants under the Credit Facility. Our ability to comply with financial covenants in future periods depends, among other things, on the success of our development program and other factors beyond our control, such as market demand and prices for natural gas, oil and NGL. See Note 4, *Credit Facility*, of the notes to our consolidated financial statements included in this report for further discussion of the terms of the Credit Facility.

Second Lien Term Loans

Our 2025 Second Lien Term Loans mature on November 1, 2025, and interest is payable quarterly, beginning with January 13, 2021, at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor. Our 2025 Second Lien Term Loans are secured by second liens on substantially all of our assets, including our natural gas and oil properties. As of December 31, 2021, we had $549.8 million in aggregate principal amount of 2025 Second Lien Term Loans outstanding, and we were in compliance with all applicable covenants under the 2025 Second Lien Term Loans.

Senior Notes

The following table summarizes certain material terms of our outstanding Senior Notes as of December 31, 2021:

($ in thousands)	2026 Notes	2027 Notes[(a)]	2028 Notes	2029 Notes
Outstanding principal	$600,000	$348,294	$300,000	$400,000
Interest rate	7.00%	9.00%	8.25%	5.875%
Maturity date	November 1, 2026	November 1, 2027	December 31, 2028	June 30, 2029
Interest payment dates	May 1, Nov. 1	May 1, Nov. 1	Feb. 1, Aug. 1	Mar. 1, Sept. 1
Make-whole redemption end date[(b)]	November 1, 2021	November 1, 2026	February 1, 2024	September 1, 2024

(a) The 2027 Notes also contain a contingent payment right which entitles the holders to receive a fixed amount of cash or equity that, as of December 31, 2021, ranged from 35% to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if certain triggering events occur. The contingent payment right is required to be bifurcated, and as of December 31, 2021, the estimated fair value was $85.2 million. See Note 4, *Senior Notes*, and Note 6, *Contingent Payment Right*, of the notes to our consolidated financial statements included in this report for further discussion of the contingent payment right.

(b) See Note 4, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of the terms and early redemption dates and prices for the Senior Notes.

Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of our outstanding Senior Notes at a price of 101.00%, plus accrued and unpaid interest. The outstanding Senior Notes each have certain conditions set forth under which they may be redeemed prior to maturity.

The Senior Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured debt and will rank senior in right of payment to all our future subordinated debt. The outstanding Senior Notes are effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness. Our obligations under the outstanding Senior Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. As of December 31, 2021, we were in compliance with all applicable covenants of the indentures governing the Senior Notes.

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2021, our material contractual obligations included repayments, outstanding borrowings and interest payment obligations under our Credit Facility and Senior Notes, derivative obligations, asset retirement obligations, lease obligations, letters of credit, surety bonds and various other commitments we enter into in the ordinary course of business that could result in future cash obligations. In addition, we have entered into certain pipeline capacity commitments with various counterparties, some of which extend beyond 20 years, in order to facilitate the delivery of our production to market and reduce the likelihood of possible production curtailments that may arise due to limited capacity. The estimated gross undiscounted future commitments under these pipeline agreements were approximately $8.11 billion as of December 31, 2021. As discussed above, we believe our existing sources of liquidity will be sufficient to fund our near and long-term contractual obligations. See Notes 1, 4, 5, 9 and 10 of the notes to our consolidated financial statements included in this report for further discussion. We do not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in accordance with GAAP, which requires management to make assumptions and estimates about future events and apply judgments that affect the reported amounts of assets, liabilities, revenues, expenses and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in Note 1, *Summary of Significant Accounting Policies*, of the notes to our consolidated financial statements included in this report. Management believes that the following accounting estimates are those most critical to fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

Natural Gas, Oil and NGL Reserves

Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of our estimates. Proved reserves are defined by the SEC as the quantities of natural gas, oil and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations. There are numerous uncertainties inherent in estimating quantities and values of economically recoverable natural gas, oil and NGL reserves, including many factors beyond our control. As a result, estimates of economically recoverable reserves are by their nature uncertain. The accuracy of reserve estimates is a function of the quality and quantity of available data, interpretation of that data, accuracy of various mandated economic assumptions, and judgment of the independent reserve engineer.

Natural gas, oil and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs, and these estimates are inherently uncertain.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for our properties will change, assuming no change in production volumes or the capitalized costs. While depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to prolong depletion expense recognition. Additionally, a decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of natural gas and oil properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

We are unable to predict future commodity prices, and the volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs. We cannot predict what reserve revisions may be required in future periods.

We believe the estimates related to natural gas, oil and NGL reserves are critical because we must periodically reevaluate proved reserves along with estimates of future production rates and the timing and amount of future development and operating costs. Our future results of operations and balance sheet for any particular quarterly or annual period could be materially affected by changes in these assumptions.

Natural Gas and Oil Properties

We account for the exploration and development of our natural gas and oil properties under the successful efforts method of accounting. Under the successful efforts method, the costs of undeveloped leases and the costs incurred to acquire, drill and complete productive wells and development wells are capitalized. Geological and geophysical expenses, delay rentals for undeveloped leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized and charged to expense if and when we determine that the well does not contain proved reserves. We did not incur any such charges in the years ended December 31, 2021, 2020 or 2019. The application of the successful efforts method of accounting requires management's judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2021, 2020 or 2019. We cannot predict whether impairment charges may be required in the future as commodity prices of natural gas, oil and NGL have a significant impact on determining future impairments. If natural gas, oil and NGL prices decrease or drilling efforts are unsuccessful, we may be required to record an impairment.

We believe that estimates related to the impairment of proved properties are critical because the process to estimate undiscounted future cash flows requires considerable judgment and are sensitive to changes in management's assumptions and estimates of future financial results. In addition, if the carrying amount exceeds the estimated undiscounted future cash flows, we would be required to estimate the fair value of our properties. Different assumptions and estimates could materially impact the calculated undiscounted future cash flows and the resulting determinations about the impairment of proved properties, which could materially impact our results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions. We evaluate the carrying amount of our proved natural gas and oil properties for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. As of December 31, 2021, no such event or change in circumstances had occurred.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on any estimated impairments would be impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

Unproved natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis, and if the assessment indicates an impairment, a loss is recorded to exploration expense. For individually insignificant unproved properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. Our impairment assessments are affected by factors including, but not limited to, our results of exploration activities, commodity price outlooks, our anticipated drilling program, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2021, 2020 and 2019, we recorded impairments of $79.0 million, $100.2 million and $115.8 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

Derivatives

We enter into commodity derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. All commodity derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized on our statements of operations within operating revenues as commodity derivative (loss) gain. We have estimated the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

Our derivative instruments expose us to counterparty credit risk, which arises due to the risk of loss from counterparties not performing under the terms of a derivative contract. To minimize such risk, we only enter into derivative contracts with counterparties that we determine are creditworthy, which includes performing both quantitative and qualitative assessments of these counterparties, based on their credit ratings and credit default swap rates where applicable. Additionally, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. Any non-performance risk is considered in the valuation of our derivative instruments, but to date it has not had a material impact on the values of our derivatives. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of our derivative instruments.

We believe the estimates related to derivative instruments are critical because our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments due to the volatility of natural gas, oil and NGL prices. Future results of operations for any particular quarterly or annual period could be materially affected by changes in our assumptions.

New Accounting Pronouncements

See Note 1, *Adopted and Recently Issued Accounting Pronouncements,* of the notes to our consolidated financial statements included in this report for a description of recent accounting pronouncements.

Quantitative and Qualitative Disclosure About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk as well as how we view and manage our exposure to such risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, oil and NGL prices, customer credit and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Demand and Price Risk

Our primary market risk exposure is in the prices we receive for our natural gas, oil and NGL production. Realized pricing is primarily driven by spot regional market prices applicable to our natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production is volatile and unpredictable, and we expect this volatility to continue in the future. The prices we expect to receive for our natural gas, oil and NGL production will depend on many factors outside of our control, including the supply of, and demand for, natural gas, oil and NGL, the level of economic activity in the United States and globally, the performance of specific industries and the volatility of natural gas, oil and NGL prices at various delivery points. During 2021, 2020 and 2019, the average daily Henry Hub spot market price of natural gas was $3.82 per mmbtu, $1.99 per mmbtu and $2.51 per mmbtu, respectively, and the average daily WTI oil price was $68.11 per bbl, $39.34 per bbl and $57.04 per bbl, respectively. Approximately 89% of our December 31, 2021 proved reserves were natural gas; therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing.

We use derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our anticipated operating cash flow against significant market movements or volatility. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. We do not use derivative instruments for speculative or trading purposes. Under the Credit Facility agreement, we are permitted to hedge up to 90% of our forecasted production for any month during the next 36 months. Additionally, we may enter into commodity derivative contracts with terms greater than 36 months, and for no longer than 66 months, for up to 80% of the forecasted production from our proved reserves for any month. As of December 31, 2021, approximately 1,471,000 mmbtu/d of our projected natural gas production for 2022 were hedged at a weighted average floor price of $2.70 per mmbtu, and approximately 850,000 mmbtu/d of our projected natural gas production for 2023 were hedged at a weighted average floor price of $2.69 per mmbtu, excluding the sold puts on our three-way collars. Additionally, as of December 31, 2021, approximately 5,000 bbls/d of our projected oil production for 2022 were hedged at a weighted average floor price of $57.50 per bbl, and approximately 2,000 bbls/d of our projected oil production for 2023 were hedged at a weighted average floor price of $62.78 per bbl. Our open hedge positions as of December 31, 2021 had maturities extending through December 2024. We also have basis swaps to mitigate portions of our basis exposure. Our market risk associated with commodity prices did not materially change from December 31, 2020 to December 31, 2021. See Note 5 of the notes to our consolidated financial statements included in this report for a summary of our commodity hedge position as of December 31, 2021.

The fair value of our commodity derivative instruments is largely influenced by the future prices of natural gas, oil and NGL. The following table sets forth the changes in the fair value of our commodity derivative instruments due to a hypothetical 10% change in future prices as of December 31, 2021. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual revenue received from the sale of our production associated with the derivative instrument.

($ in thousands)	Hypothetical 10% Increase in Future Prices	Hypothetical 10% Decrease in Future Prices
Natural gas	$ (393,696)	$ 380,362
Oil	$ (20,225)	$ 20,225
NGL	$ (7,568)	$ 7,568

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations within operating revenues as commodity derivative (loss) gain.

Although mark-to-market adjustments of derivative instruments cause earnings volatility, our cash flows are only impacted when the associated derivative contracts are settled or are monetized prior to settlement by making or receiving payments to or from the counterparty. We expect continued volatility in the fair value of our derivative instruments. As of December 31, 2021, the estimated fair value of our commodity derivative positions was a net liability of $1.08 billion comprised of current and long-term assets and liabilities.

By removing price volatility from a portion of our future expected production, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we receive from the increases in commodity prices above the fixed hedge ceiling prices.

Counterparty Credit Risk

Our derivative instruments expose us to counterparty credit risk, which arises due to the risk of loss from counterparties not performing under the terms of a derivative contract. Adverse moves within the financial or commodities markets could negatively impact our counterparties' ability to fulfill obligations to us. To minimize such risk, we only enter into derivative contracts with counterparties that we determine are creditworthy, which includes performing both quantitative and qualitative assessments of these counterparties, based on their credit ratings and credit default swap rates where applicable. Additionally, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty.

Customer Credit Risk

We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables; however, we do not believe the loss of any single customer would materially impact our operating results. We also have joint interest receivables, which arise from billings to entities that own working interests in the wells we operate, but historically we have not incurred any material losses. Please see Note 1 of the notes to our consolidated financial statements included in this report for a discussion of our credit and concentration risk.

Interest Rate Risk

Certain of our debt instruments bear interest at floating rates based on LIBOR, and the LIBOR component of our interest on these instruments exposes us to interest rate risk. Borrowings under the Credit Facility bear interest at a floating tiered rate based on facility usage plus the 1-month LIBOR, resulting in a weighted average interest rate of 2.35% as of December 31, 2021. Additionally, our 2025 Second Lien Term Loans bear interest at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor, resulting in a weighted average interest rate of 10.00% as of December 31, 2021. A 1.00% increase in both the 1-month and 3-month LIBOR in 2021 would have resulted in an estimated increase of $9.9 million in interest expense on borrowings under the Credit Facility and 2025 Second Lien Term Loans.

Report of Independent Auditors

To the Board of Managers and Management of Ascent Resources Utica Holdings, LLC

Opinion

We have audited the accompanying consolidated financial statements of Ascent Resources Utica Holdings, LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2021 and 2020, and the related consolidated statements of operations, of member's equity and of cash flows for each of the three years in the period ended December 31, 2021, including the related notes (collectively referred to as the "consolidated financial statements").

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

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In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises Business Overview, Properties, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk, but does not include the consolidated financial statements and our auditors' report thereon. Our opinion on the consolidated financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the consolidated financial statements or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 10, 2022

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED BALANCE SHEETS

($ in thousands)	December 31, 2021	December 31, 2020
Current Assets:		
Cash and cash equivalents	$ 5,674	$ 8,843
Accounts receivable – natural gas, oil and NGL sales	453,464	223,976
Accounts receivable – joint interest and other	8,309	8,466
Short-term derivative assets	6,866	8,202
Other current assets	9,012	8,316
Total Current Assets	483,325	257,803
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	9,383,879	8,790,870
Other property and equipment	36,318	34,076
Less: accumulated depreciation, depletion and amortization	(3,225,844)	(2,628,150)
Property and Equipment, net	6,194,353	6,196,796
Other Assets:		
Long-term derivative assets	522	2,401
Other long-term assets	46,241	34,560
Total Assets	$ 6,724,441	$ 6,491,560
Current Liabilities:		
Accounts payable	$ 86,812	$ 36,736
Accrued interest	45,929	31,287
Current portion of long-term debt, net	—	12,498
Short-term derivative liabilities	648,873	54,144
Other current liabilities	517,953	354,169
Total Current Liabilities	1,299,567	488,834
Long-Term Liabilities:		
Long-term debt, net of current portion	2,588,248	2,707,382
Long-term derivative liabilities	435,022	113,160
Other long-term liabilities	104,796	79,594
Total Long-Term Liabilities	3,128,066	2,900,136
Commitments and contingencies (Note 10)		
Member's Equity	2,296,808	3,102,590
Total Liabilities and Member's Equity	$ 6,724,441	$ 6,491,560

The accompanying notes are an integral part of these consolidated financial statements.

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

($ in thousands)	Year Ended December 31, 2021	2020	2019
Revenues:			
Natural gas	$ 2,510,150	$ 1,258,594	$ 1,589,099
Oil	188,076	138,723	241,521
NGL	241,731	118,224	148,639
Commodity derivative (loss) gain	(1,743,892)	(19,167)	441,139
Total Revenues	1,196,065	1,496,374	2,420,398
Operating Expenses:			
Lease operating expenses	90,719	77,521	71,968
Gathering, processing and transportation expenses	936,134	919,986	856,126
Taxes other than income	38,988	37,495	34,167
Exploration expenses	83,367	104,230	124,477
General and administrative expenses	58,334	63,825	61,027
Depreciation, depletion and amortization	598,407	737,717	705,892
Total Operating Expenses	1,805,949	1,940,774	1,853,657
(Loss) Income from Operations	(609,884)	(444,400)	566,741
Other (Expense) Income:			
Interest expense, net	(174,840)	(134,259)	(109,135)
Change in fair value of contingent payment right	(19,921)	(6,518)	—
Change in fair value of embedded derivative	—	—	5,026
Losses on purchases or exchanges of debt	(3,822)	(6,037)	—
Other income	2,182	1,850	3,781
Total Other Expense	(196,401)	(144,964)	(100,328)
Net (Loss) Income	$ (806,285)	$ (589,364)	$ 466,413

The accompanying notes are an integral part of these consolidated financial statements.

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY

($ in thousands)	Year Ended December 31, 2021	2020	2019
Balance, Beginning of Period	$ 3,102,590	$ 3,681,831	$ 3,215,097
Contributions from Member	3,737	10,123	321
Distributions to Member	(3,234)	—	—
Net (loss) income	(806,285)	(589,364)	466,413
Balance, End of Period	$ 2,296,808	$ 3,102,590	$ 3,681,831

The accompanying notes are an integral part of these consolidated financial statements.

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in thousands)	Year Ended December 31, 2021	2020	2019
Cash Flows from Operating Activities:			
Net (loss) income	$ (806,285)	$ (589,364)	$ 466,413
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	598,407	737,717	705,892
Change in fair value of commodity derivatives	920,376	475,027	(249,457)
Change in fair value of interest rate derivatives	(570)	569	—
Impairment of unproved natural gas and oil properties	78,993	100,207	115,802
Non-cash interest expense	18,871	25,347	27,305
Stock-based compensation	3,616	1,775	—
Change in fair value of contingent payment right	19,921	6,518	—
Change in fair value of embedded derivative	—	—	(5,026)
Losses (gains) on purchases or exchanges of debt	3,810	(11,500)	—
Other	11,348	(1,560)	78
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable and other assets	(249,315)	40,136	144,258
Increase (decrease) in accounts payable, liabilities and other	161,465	(11,036)	(64,591)
Net Cash Provided by Operating Activities	760,637	773,836	1,140,674
Cash Flows from Investing Activities:			
Drilling and completion costs	(508,311)	(571,860)	(1,125,216)
Acquisitions of natural gas and oil properties	(89,360)	(139,106)	(258,001)
Proceeds from divestitures of natural gas and oil properties	—	—	12,474
Additions to other property and equipment	(1,444)	(1,509)	(3,547)
Net Cash Used in Investing Activities	(599,115)	(712,475)	(1,374,290)
Cash Flows from Financing Activities:			
Proceeds from credit facility borrowings	2,100,000	1,065,000	1,270,000
Repayment of credit facility borrowings	(2,558,000)	(1,300,000)	(1,030,000)
Proceeds from issuance of long-term debt	400,000	300,000	—
Repayment of long-term debt	(84,173)	(138,764)	—
Proceeds from the Exchange	—	20,000	—
Cash paid for debt issuance costs	(7,229)	(6,842)	(9,512)
Commodity derivative settlements	(11,188)	1,557	—
Other	(4,101)	(815)	(556)
Net Cash (Used in) Provided by Financing Activities	(164,691)	(59,864)	229,932
Net (Decrease) Increase in Cash and Cash Equivalents	(3,169)	1,497	(3,684)
Cash and Cash Equivalents, Beginning of Period	8,843	7,346	11,030
Cash and Cash Equivalents, End of Period	$ 5,674	$ 8,843	$ 7,346

	2021	2020	2019
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest and interest paid in kind	$ 142,576	$ 115,589	$ 88,392
Supplemental disclosures of significant non-cash investing activities:			
Increase (decrease) in accrued capital expenditures	$ 72,025	$ (57,925)	$ (96,471)

The accompanying notes are an integral part of these consolidated financial statements.

1. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Ascent Resources Utica Holdings, LLC ("ARUH"), together with its wholly-owned subsidiaries (collectively, "we," "our" or "us"), is engaged in the acquisition, exploration, development, production and operation of natural gas and oil properties located in the Utica Shale in Ohio (the "Utica Shale"). ARUH is a wholly-owned subsidiary of Ascent Resources Operating, LLC (our "Member"), which is an indirect, wholly-owned subsidiary of Ascent Resources, LLC (our "Parent"). Together, The Energy & Minerals Group ("EMG") and First Reserve Corporation ("First Reserve") own a majority interest in our Parent.

Our accompanying consolidated financial statements and notes were prepared in accordance with accounting principles generally accepted in the United States ("GAAP"), and intercompany accounts and balances have been eliminated.

Business Segment Information

We evaluated how we are organized and managed and identified only one operating segment, which is the exploration, development and production of natural gas, oil and NGL in the United States. Operating segments are defined as components of an enterprise that engage in business activities from which it may earn revenues and incur expenses for which discrete operational financial information is available and this information is regularly reviewed by the chief operating decision makers to make decisions about the allocation of resources and assessment of performance.

We have a single, company-wide management team that manages all properties as a whole rather than by various distinct operating segments. We measure financial performance as a single enterprise and not on a geographical basis.

Use of Estimates

The preparation of consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures on the consolidated financial statements. Actual amounts could differ from these estimates. Estimates of natural gas, oil and NGL reserves are the most significant of our estimates, which are the basis of the calculation of the depletion and impairment of natural gas and oil properties. Other items in our consolidated financial statements that involve the use of significant estimates include business combinations, derivative assets and liabilities, accrued revenue, and commitments and other contingencies.

Summary of Significant Accounting Policies

Cash and Cash Equivalents. We consider investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. We maintain our cash in accounts that may not be federally insured beyond certain limits; however, we have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on such accounts.

Accounts Receivable. We sell natural gas, oil and NGL to various customers and participate with other companies in the drilling, completion and operation of natural gas and oil wells. Accounts receivable at December 31, 2021 and 2020 were $461.8 million and $232.4 million, respectively, and consisted primarily of accrued natural gas, oil and NGL revenue receivables and receivables from joint interest billings to owners of properties we operate. Receivables are considered past due if full payment is not received by the contractual due date. If we had past due accounts, they would generally be written off against the allowance for doubtful accounts after all attempts to collect the balance are exhausted. All accounts receivable are considered to be fully collectible; therefore, no allowance for doubtful accounts is recorded in the consolidated balance sheets as of December 31, 2021 or 2020.

Natural Gas and Oil Properties. We account for the exploration and development of our natural gas and oil properties under the successful efforts method of accounting. Under the successful efforts method, the costs of undeveloped leases and the costs incurred to acquire, drill and complete productive wells and development wells are capitalized. Geological and geophysical expenses, delay rentals for undeveloped leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized and charged to expense if and when we determine that the well does not contain proved reserves. We did not incur any such charges in the years ended December 31, 2021, 2020 or 2019. The application of the successful efforts method of accounting requires management judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2021, 2020 or 2019. We cannot predict whether impairment charges may be required in the future as commodity prices of natural gas, oil and NGL have a significant impact on determining future impairments.

Unproved natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis, and if the assessment indicates an impairment, a loss is recorded to exploration expense. For individually insignificant unproved properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. Our impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, our anticipated drilling program, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2021, 2020 and 2019, we recorded impairments of $79.0 million, $100.2 million and $115.8 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

Natural Gas and Oil DD&A. DD&A of capitalized drilling and completion costs related to developed natural gas and oil properties is computed using the unit-of-production method, based on total estimated proved developed natural gas, oil and NGL reserves. Costs of acquiring proved properties, including leasehold acquisition costs and capitalized interest transferred from unproved properties, are depleted using the unit-of-production method based on total estimated proved natural gas, oil and NGL reserves. DD&A expense for natural gas and oil properties was $595.5 million, $733.5 million and $702.4 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Other Property and Equipment. Other property and equipment is recorded at cost. Upon retirement or disposition of assets, the cost and related accumulated depreciation are removed from the balance sheet with the resulting gain or loss, if any, recorded to other income on the statements of operations. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the related assets generally ranging from three to seven years. Our field office location is depreciated using the straight-line method over the estimated useful life of 39 years. Depreciation expense for other property and equipment was $2.9 million, $4.3 million and $3.5 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Business Combinations. Accounting for business combinations involves the use of significant judgment. In a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill.

The most significant assumptions in a business combination include those used to estimate the fair value of the natural gas and oil properties acquired. The fair value of proved and unproved natural gas and oil properties is estimated using an after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; risk factors applied to reserves by type; projections of future rates of production; timing and amount of future development and operating costs; and a market-based weighted average cost of capital.

Asset Acquisitions. As part of our business strategy, we periodically pursue the acquisition of natural gas and oil properties. The purchase price in an asset acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the effective date. Therefore, while the consideration to be paid may be fixed, the relative fair value of the assets acquired and liabilities assumed is subject to change during the period between the effective date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable natural gas, oil and NGL reserves and unproved natural gas and oil properties.

Asset Retirement Obligations. We are obligated to retire our natural gas and oil wells at the end of their lives. We recognize the fair value of a liability for a retirement obligation in the period in which a natural gas or oil well is acquired or spud and accrete it to its present value each period, until the well is retired or sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our natural gas and oil properties and expensed through depletion of the asset as a component of DD&A on our consolidated statements of operations. The associated liabilities were $8.6 million and $5.9 million as of December 31, 2021 and 2020, respectively.

Capitalized Interest. We capitalize interest on expenditures made in connection with exploration and development projects, which include developing and constructing assets that have not yet commenced production and investments in unproved natural gas and oil properties. Capitalized interest is determined by multiplying our weighted average interest rate, based on our outstanding borrowings, by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

Debt Issuance Costs. Debt issuance costs associated with our term debt have been presented as a reduction to long-term debt on the consolidated balance sheets and are amortized through their respective maturity dates using the effective interest method. The amortization of debt issuance costs is recorded in interest expense on the consolidated statements of operations.

Debt issuance costs associated with the Credit Facility have been presented as other long-term assets on the consolidated balance sheets and are amortized over the scheduled maturity period of the facility on a straight-line basis, which approximates the effective interest method. The amortization of debt issuance costs associated with the Credit Facility is recorded in interest expense on the consolidated statements of operations.

Revenue Recognition. Revenue from the sale of natural gas, oil and NGL is recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. We recognize revenue from the sale of natural gas, oil and NGL based on our share of volumes sold. See Note 2 for further discussion of our revenues from contracts with customers.

Credit and Concentration Risk. We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables. If our largest customers stopped purchasing our natural gas, oil or NGL, our revenues could decline and our operating results and financial condition could be adversely affected. The following table provides the concentration of sales to individual customers that constitute 10% or more of our revenues, before the effects of derivatives, for the periods indicated:

	% of Sales
Year Ended December 31, 2021	
Company A	14 %
Company B	11 %
Year Ended December 31, 2020	
Company A	13 %
Year Ended December 31, 2019	
Company A	10 %
Company B	16 %

We do not believe the loss of any single customer would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets, and we transact with numerous customers in our operating region. We historically have not incurred any material losses on our natural gas, oil and NGL receivables.

We also have joint interest receivables, which arise from billings to entities that own working interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases. We have little ability to control whether these entities will participate in our wells but can require these entities to prepay drilling costs. We historically have not incurred any material losses on our joint interest receivables.

By using derivative instruments, we are also exposed to credit risk associated with our hedge counterparties. To minimize such risk, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. In addition, we only enter into derivative contracts with counterparties that we determine are creditworthy, and such creditworthiness is subject to periodic review. Any non-performance risk is considered in the valuation of our derivative instruments, but to date it has not had a material impact on the values of our derivatives. See Note 5 for further discussion of our derivative instruments.

Fair Value of Financial Instruments. Certain financial instruments are reported at fair value on the consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

Derivatives. We enter into derivative instruments to reduce our exposure to fluctuations in future commodity prices and floating interest rates in order to protect our expected operating cash flow against significant market movements or volatility. All derivative instruments are recognized at their current fair value as either assets or liabilities on the consolidated balance sheets. We have estimated the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Changes in the fair value of these derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. We elected not to designate any of our commodity derivative instruments for hedge accounting treatment.

Our derivative instruments reflected as current on the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices or rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows on the accompanying consolidated statements of cash flows. All of our derivative instruments are subject to International Swaps and Derivatives Association ("ISDA") master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, by counterparty. ISDA master agreements also provide for net settlement over the term of the contract and in the event of default or termination of the contract. We net the value of our derivative instruments by counterparty on the accompanying consolidated balance sheets. See Note 5 for further discussion of our derivative instruments.

Stock-Based Compensation. We recognize compensation cost for equity-classified awards based on the fair value on the date of the grant, and such amount is recognized on a straight-line basis over the requisite service period. Compensation cost for liability-classified awards is recognized once it becomes probable that such awards will be settled, and the cost is measured at fair value as of the date it becomes probable and is re-measured at fair value at the end of each reporting period. Stock-based compensation is presented as general and administrative expenses on the consolidated statements of operations. See Note 7 for further discussion of our stock-based compensation.

Leases. We adopted Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)*, as of January 1, 2019. Accounting Standards Codification 842 ("ASC 842") supersedes the previous lease accounting requirements ("ASC 840") and requires lessees to recognize leases on the balance sheet and disclose key information about leasing arrangements. We adopted using the modified retrospective transition approach, which allows companies to account for leases prior to adoption under ASC 840, which was the guidance in place at the time of the original reporting.

We capitalize our leases to our consolidated balance sheet through a right-of-use ("ROU") asset and a corresponding lease liability. ROU assets associated with our operating leases are presented within other long-term assets and consist of drilling rigs, real estate, compressors and other equipment, with corresponding lease liabilities reflected as other current liabilities and other long-term liabilities on the consolidated balance sheets. ROU assets associated with our financing leases are reflected as property and equipment, net and consist of commercial vehicles, with corresponding lease liabilities reflected as other current liabilities and other long-term liabilities on the consolidated balance sheets. Short-term leases that have an initial term of one year or less are not capitalized to the consolidated balance sheet, and instead are recognized as lease costs in accordance with the lease terms. As of December 31, 2021 and 2020, we were not a lessor.

Our leases are recognized at the commencement date of an arrangement and the associated ROU assets and lease liabilities are based on the present value of the minimum lease payments over the lease term. Most leases do not provide an implicit interest rate; therefore, we use our incremental borrowing rate based on information available at the inception date to determine the present value of the lease payments. Certain leases may also contain variable payments. Variable payments that do not depend on an index or rate are excluded from lease payments at lease commencement for initial measurement. Subsequent to initial measurement, these variable payments are recognized in the period in which the obligation for the payment is incurred.

Certain leases include options to renew on a month-to-month basis; however, they are not recognized as part of the ROU assets or lease liabilities as they are not reasonably certain to be exercised.

We have made an accounting policy election to combine lease and non-lease components on an asset class basis, which allows us to account for them as a single lease component. See Note 9 for further information on our leases.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources, or for environmental remediation or restoration claims resulting from allegations of improper operation of assets, are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with our accounting policy for natural gas and oil properties.

Income Taxes. We are treated as a disregarded entity for income tax purposes. Our Parent is treated as a partnership for income tax purposes, with each partner being separately taxed on their share of income. As such, no income taxes are shown on our consolidated financial statements.

Reclassifications

Certain reclassifications have been made to our 2020 and 2019 consolidated financial statements to conform to the presentation used for the 2021 consolidated financial statements.

Adopted and Recently Issued Accounting Pronouncements

In August 2020, the Financial Accounting Standards Board ("FASB") issued ASU 2020-06, *Debt - Debt with Conversion and Other Options, Subtopic 470-20, and Derivatives and Hedging - Contracts in Entity's Own Equity, Subtopic 815-40.* This ASU modifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity, and adds new disclosure requirements. The amendments are effective for annual reporting periods, and interim periods within those periods, beginning after December 15, 2021 for public entities. For non-public entities, the amendments are effective for annual reporting periods beginning after December 15, 2023, including interim periods within those fiscal years. Entities may elect to apply the amendments in this guidance using either the modified retrospective method or the full retrospective method. The adoption of this guidance is not expected to have a material impact on our financial statements and related disclosures.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments, Topic 326*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and instead requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposures, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. These amendments were effective for annual reporting periods, and interim periods within those periods, beginning after December 15, 2019 for public entities. For non-public entities, the amendments will be effective for annual reporting periods beginning after December 15, 2022, including interim periods within those fiscal years. The amendments in this guidance should be applied using the modified retrospective approach with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We adopted ASU 2016-13 effective January 1, 2021, and did not experience a material impact to our financial statements or disclosures.

Subsequent Events

As of March 10, 2022, the date the consolidated financial statements were issued, we completed our evaluation of material subsequent events for disclosure, and no items were noted.

2. Revenue from Contracts with Customers

Our revenues are derived from the sale of natural gas, oil and NGL and are recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. We typically receive payment for natural gas, oil and NGL sales within 30 days of the month of delivery. A significant number of our sales contracts are short-term in nature, generally through evergreen contracts with terms of one year or less, and our sales contracts with a term greater than one year have no material long-term fixed consideration.

Under our natural gas sales contracts, we deliver natural gas to the customer at a delivery point specified under the sales contracts, utilizing third parties to gather, compress, process and transport our natural gas. Our sales contracts provide that we generally receive revenue for the sale of our natural gas based on a specific index price adjusted for pricing differentials. We transfer control of the natural gas at the delivery point and recognize revenue based on the contract price. The costs incurred to gather, compress, process and transport the natural gas prior to the point when control is transferred to the customer are recorded on the consolidated statements of operations as gathering, processing and transportation expenses.

NGL, which are extracted from natural gas through processing, are either sold by us directly or to the processor under processing contracts. For NGL sold by us directly, the sales contracts provide that the product is delivered to the customer at an agreed upon delivery point and that we generally receive revenue for the sale of our NGL based on a specific index price adjusted for pricing differentials. We transfer control of the product to the customer at the delivery point and recognize revenue based on the contract price. The costs to process and transport NGL to the delivery points are recorded on the consolidated statements of operations as gathering, processing and transportation expenses. For NGL sold to the processor, control is transferred by us to the processor at the tailgate of the processing plant, and revenue is recognized based on the price received from the processor.

Under our oil sales contracts, oil is sold to the customer from storage tanks near the wellhead, and we receive revenue for the sale of our oil based on a specific index price adjusted for pricing differentials. We transfer control of the product to the customer at the storage tanks and recognize revenue based on the contract price.

Our revenues from the sale of natural gas, oil and NGL are each presented separately on our consolidated statements of operations. We believe that the disaggregation of revenue into these three major product types appropriately depicts the accounting guidance for revenue recognition.

Under our sales contracts, customers are invoiced after our performance obligations have been satisfied, generally when control of the product has been transferred to the customer, at which point payment is unconditional. Accordingly, we have no contract assets or contract liabilities associated with our revenues from contracts with customers. As of December 31, 2021 and 2020, receivables from contracts with customers were $453.5 million and $224.0 million, respectively, and were reported in accounts receivable – natural gas, oil and NGL sales on the consolidated balance sheets.

3. Property and Equipment

Net property and equipment included the following as of the dates indicated:

	December 31,	
($ in thousands)	**2021**	**2020**
Proved natural gas and oil properties	$ 8,560,861	$ 7,752,572
Unproved natural gas and oil properties	823,018	1,038,298
Other property and equipment	36,318	34,076
Total Property and Equipment	9,420,197	8,824,946
Accumulated depreciation, depletion and amortization	(3,225,844)	(2,628,150)
Property and Equipment, net	$ 6,194,353	$ 6,196,796

As of December 31, 2021 and 2020, we did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

4. Debt

Our debt consisted of the following as of the dates indicated:

($ in thousands)	December 31, 2021	December 31, 2020
Long-Term Debt:		
Credit Facility[(a)]	$ 495,000	$ 953,000
Second lien term loans due November 2025[(b)]	549,822	549,822
7.00% senior notes due November 2026	600,000	600,000
9.00% senior notes due November 2027	348,294	348,294
8.25% senior notes due December 2028	300,000	300,000
5.875% senior notes due June 2029	400,000	—
10.00% senior notes due April 2022[(c)]	—	67,992
Net debt issuance costs	(13,675)	(8,248)
Net debt discounts and premiums	(91,193)	(103,478)
Total Long-Term Debt, net of current portion	2,588,248	2,707,382
Plus current maturities of long-term debt, net[(d)]	—	12,498
Total Debt, net	$ 2,588,248	$ 2,719,880

(a) The interest rate was 2.35% and 2.65% as of December 31, 2021 and 2020, respectively.
(b) The interest rate was 10.00% as of December 31, 2021 and 2020.
(c) On April 1, 2021, the 2022 Notes were redeemed at 105.00% of the outstanding principal value for $71.4 million, plus accrued and unpaid interest.
(d) The Convertible Notes matured on March 1, 2021, and were redeemed for $12.8 million, which included a premium that was accreted over the life of the Convertible Notes, plus accrued and unpaid interest. The interest rate was 6.50% as of December 31, 2020.

Credit Facility

Our $2.5 billion Credit Facility matures on April 1, 2024, and as of December 31, 2021, it had a fully committed borrowing base of $1.85 billion, of which $250.0 million was authorized for letters of credit. The Credit Facility is secured by liens on substantially all of our assets, including our natural gas and oil properties. The amount available to be borrowed under our Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about May 1 and November 1 of each year primarily based on the estimated value and future net cash flows of our proved natural gas, oil and NGL reserves and the value of our commodity hedge positions as determined by lenders under the Credit Facility at their discretion. Additionally, we may request an interim redetermination of the borrowing base in certain circumstances, including acquisitions of proved reserves in excess of certain thresholds. In November 2021, the borrowing base under the Credit Facility was reaffirmed at $1.85 billion. As of December 31, 2021, we had $495.0 million of borrowings outstanding and $169.2 million of letters of credit issued under the Credit Facility.

Under the Credit Facility agreement, we may borrow either base rate loans or Eurodollar loans, and as of December 31, 2021, all of the borrowings under the Credit Facility were Eurodollar loans. Principal amounts borrowed are payable on the maturity date and may be repaid prior to the maturity date without any premium or penalty. Interest is payable at the end of the applicable interest period. Eurodollar loans bear interest at a rate per annum equal to the London Interbank Offered Rate ("LIBOR") plus an applicable margin ranging from 2.00% to 3.00% per annum based on Credit Facility utilization. Due to the weighted average 1-month LIBOR being 0.10% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 2.35% per annum as of December 31, 2021.

Under the Credit Facility agreement, we are subject to commitment fees payable to the administrative agent for the unutilized portion of our available borrowing base, the rate of which ranges from 0.375% to 0.50% based on Credit Facility utilization. Additionally, we are subject to letter of credit participation fees payable to the administrative agent which escalate based on applicable margins, ranging from 2.00% to 3.00% per annum, in accordance with the Credit Facility utilization. We are also subject to a letter of credit fronting fee that is payable to the issuing bank at a rate of 0.125% per annum of the balance of outstanding letters of credit issued.

We had $11.0 million and $16.1 million as of December 31, 2021 and 2020, respectively, in unamortized debt issuance costs associated with the Credit Facility, which are presented as part of other long-term assets on the consolidated balance sheets.

Second Lien Term Loans

In October 2020, we issued $537.8 million in aggregate principal amount of 2025 Second Lien Term Loans and $339.7 million in aggregate principal amount of 2027 Notes in a private placement to eligible purchasers in exchange for $856.7 million of aggregate principal amount of 2022 Notes (the "Exchange"). We accounted for the Exchange as a modification to existing debt, and no gain or loss was recognized related to the principal exchanged. However, we incurred $17.7 million of fees related to the Exchange during the year ended December 31, 2020, which are presented as a loss on purchases or exchanges of debt on the consolidated statements of operations. In connection with the Exchange, we issued an additional $12.0 million in aggregate principal amount of 2025 Second Lien Term Loans, $8.6 million in aggregate principal amount of 2027 Notes and equity of our Parent to certain existing equity holders and their designated affiliates in exchange for an aggregate contribution of $20.0 million in cash. The proceeds were used to pay fees for the Exchange and to repay a portion of the borrowings outstanding under the Credit Facility. See Note 8 for further discussion of our debt held by certain related parties. The 2025 Second Lien Term Loans mature on November 1, 2025, and interest is payable quarterly, beginning with January 13, 2021, at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor. Due to the 3-month LIBOR being 0.12% for the applicable interest period, we were subject to a rate of 10.00% per annum as of December 31, 2021. The 2025 Second Lien Term Loans are secured by second liens on substantially all of our assets, including our natural gas and oil properties. Our obligations under the 2025 Second Lien Term Loans are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. We may redeem some or all of the 2025 Second Lien Term Loans at redemption prices ranging from 105.00% to 100.00% at any time on or after April 13, 2023. At any time prior to April 13, 2023, we may redeem some or all of the 2025 Second Lien Term Loans at a price of 100.00% plus a make-whole premium (as defined in the term loan credit agreement), and we may redeem up to 40% of the aggregate principal amount of 2025 Second Lien Term Loans at a price of 105.00% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2025 Second Lien Term Loans at a price of 101.00%, plus accrued and unpaid interest.

Senior Notes

2026 Notes. In October 2018, we issued $600.0 million in aggregate principal amount of 2026 Notes in a private placement to eligible purchasers. The 2026 Notes mature on November 1, 2026, and interest is payable on May 1 and November 1 of each year. We used the proceeds primarily to redeem $525.0 million of outstanding principal of the 2022 Notes and pay accrued and unpaid interest up to, but excluding, the date of the redemption. The remaining net proceeds were used to repay borrowings under the Credit Facility. We may redeem some or all of the 2026 Notes at redemption prices ranging from 103.50% to 100.00% at any time on or after November 1, 2021. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2026 Notes at a price of 101.00%, plus accrued and unpaid interest.

2027 Notes. In October 2020, we issued $339.7 million in aggregate principal amount of 2027 Notes as part of the Exchange. The 2027 Notes mature on November 1, 2027, and interest is payable at an annual rate of 9.00% on May 1 and November 1 of each year, beginning with May 1, 2021. Additionally, $8.6 million of 2027 Notes were issued to certain existing equity holders of our Parent, and their designated affiliates, the proceeds of which were used primarily to pay fees related to the Exchange. See Note 8 for further discussion of our debt held by certain related parties.

Unless and until a Triggering Event (as defined below) has occurred and we have paid all consideration payable in respect thereof, we may redeem some or all of the 2027 Notes (i) at any time prior to November 1, 2026, subject to a make-whole premium (as defined in the indenture) and (ii) on or after November 1, 2026, at a redemption price equal to 100.00% of the principal amount of 2027 Notes to be redeemed, in each case plus accrued and unpaid interest to, but excluding, the redemption date. If a Triggering Event has occurred and we have paid all consideration payable in respect thereof, we may redeem some or all of the 2027 Notes (i) at any time prior to November 1, 2023, subject to a make-whole premium and (ii) on or after November 1, 2023, at redemption prices ranging from 104.50% to 100.00%, in each case plus accrued and unpaid interest to, but excluding, the redemption date. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2027 Notes at a price of 101.00%, plus accrued and unpaid interest.

The 2027 Notes also contain a contingent payment right which entitles the holders to receive a fixed amount of cash or equity that, as of December 31, 2021, ranged from 35% to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if certain triggering events (each a "Triggering Event") occur. Triggering Event is defined to include a qualified public offering, a qualified merger or consolidation that results in our equity holders receiving an equity interest that is listed or quoted on any national securities exchange, or a change of control. The amount paid to holders of the 2027 Notes in connection with the contingent payment right is dependent upon the timing of the first occurrence of such a Triggering Event. The contingent payment right is required to be bifurcated and accounted for at fair value, and the estimated fair value was $85.2 million and $65.3 million as of December 31, 2021 and 2020, respectively, and is presented as part of other long-term liabilities on the consolidated balance sheets. See Note 6, *Contingent Payment Right*, for further discussion of the contingent payment right valuation. In certain instances, the contingent payment right may be replaced by a Contingent Value Right ("CVR"), which entitles the holder of the CVR to the same fixed amount of consideration upon a Triggering Event despite no longer holding the associated 2027 Notes. However, if the 2027 Notes are voluntarily sold to us prior to a Triggering Event through means of open market transactions or other negotiated transactions, the contingent payment right will expire.

2028 Notes. In December 2020, we issued $300.0 million in aggregate principal amount of 2028 Notes in a private placement to eligible purchasers. The 2028 Notes mature on December 31, 2028, and interest is payable on February 1 and August 1 of each year, beginning with August 1, 2021. The net proceeds were used to repay a portion of the borrowings outstanding under the Credit Facility. We may redeem some or all of the 2028 Notes at redemption prices ranging from 104.125% to 100.00% at any time on or after February 1, 2024. At any time prior to February 1, 2024, we may redeem some or all of the 2028 Notes at a price of 100.00% plus a make-whole premium (as defined in the indenture), and we may redeem up to 40% of the aggregate principal amount of 2028 Notes at a price of 108.25% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2028 Notes at a price of 101.00%, plus accrued and unpaid interest.

2029 Notes. In June 2021, we issued $400.0 million in aggregate principal amount of 2029 Notes in a private placement to eligible purchasers. The 2029 Notes mature on June 30, 2029, and interest is payable on March 1 and September 1 of each year, beginning with September 1, 2021. The net proceeds were used to repay a portion of the borrowings outstanding under the Credit Facility. We may redeem some or all of the 2029 Notes at redemption prices ranging from 102.938% to 100.00% at any time on or after September 1, 2024. At any time prior to September 1, 2024, we may redeem some or all of the 2029 Notes at a price of 100.00% plus a make-whole premium (as defined in the indenture), and we may redeem up to 40% of the aggregate principal amount of 2029 Notes at a price of 105.875% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2029 Notes at a price of 101.00%, plus accrued and unpaid interest.

2022 Notes. In April 2017, we issued $1.5 billion in aggregate principal amount of 2022 Notes in a private placement to eligible purchasers. The 2022 Notes had a maturity date of April 1, 2022, and interest was payable on April 1 and October 1 of each year. Our obligations under the 2022 Notes were fully and unconditionally guaranteed, jointly and severally, by our material subsidiaries. Through multiple transactions from 2018 to 2020, we repurchased or otherwise retired a significant portion of the 2022 Notes, including, during the year ended December 31, 2020, the repurchase of approximately $50.3 million of outstanding principal amount of the 2022 Notes at a discount for $35.4 million, plus accrued and unpaid interest, and recorded a $14.3 million gain, including the write-off of unamortized debt issuance costs and discounts. Additionally, in October 2020, we completed the Exchange which resulted in $856.7 million of aggregate principal amount of 2022 Notes being exchanged for a combination of 2025 Second Lien Term Loans and 2027 Notes. During the year ended December 31, 2021, we redeemed the remaining $68.0 million of outstanding principal amount of the 2022 Notes at a price of 105.00% of the outstanding principal value for a total of $71.4 million, plus accrued and unpaid interest, resulting in a loss of $3.8 million, including the redemption premium and the write-off of unamortized discounts and debt issuance costs.

The Senior Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured debt, and the outstanding Senior Notes will rank senior in right of payment to all of our future subordinated debt. The outstanding Senior Notes are effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness. Our obligations under the outstanding Senior Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries.

Convertible Notes

In 2014, we issued $1.0 billion of Convertible Notes. Through multiple transactions from 2015 through 2020, we repurchased or otherwise retired a significant portion of the Convertible Notes. During the year ended December 31, 2020, we repurchased $69.0 million of outstanding principal amount for $103.4 million, plus accrued and unpaid interest, resulting in a loss of $2.7 million, including the write-off of debt issuance costs, discounts and premiums. On March 1, 2021, the remaining outstanding aggregate principal of $8.3 million matured and was redeemed at a 53.8% premium for $12.8 million, plus accrued and unpaid interest.

Debt Covenants

The agreements governing our debt contain restrictive covenants including, but not limited to, restrictions on our ability to incur additional indebtedness, create certain liens on assets, make certain investments or restricted payments, make loans to others, make certain payments, consolidate or merge, hedge hydrocarbons, enter into transactions with affiliates, dispose of assets or engage in certain other transactions without the prior consent of the lenders. The Credit Facility also requires us to maintain the following two financial ratios: (i) a consolidated leverage ratio, which requires us to maintain a consolidated funded indebtedness to consolidated EBITDAX ratio for the aggregate of the last four consecutive quarters (as defined in the Credit Facility agreement) of not more than 4.00 to 1.00 for each fiscal quarter and (ii) a modified current ratio (as defined in the Credit Facility agreement), which requires us to maintain consolidated current assets to consolidated current liabilities of not less than 1.00 to 1.00 as of the end of each fiscal quarter. We were in compliance with all applicable debt covenants as of December 31, 2021.

Debt Maturities

The principal amount of debt maturities for the five years ended after December 31, 2021 and thereafter are as follows:

($ in thousands)	Principal Amount of Debt Securities
2022	$ —
2023	—
2024	495,000
2025	549,822
2026	600,000
2027 and Thereafter	1,048,294
Total	$ 2,693,116

5. Derivative Instruments

We use derivative instruments to mitigate our exposure to fluctuations in future commodity prices and floating interest rates in order to protect our anticipated operating cash flow against significant market movements or volatility. We do not use derivative instruments for speculative or trading purposes. We utilize the following types of derivative instruments:

- *Swaps*. We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity.

- *Call Options*. We sell call options in exchange for a premium, which establish the maximum price we will receive for contracted commodity volumes. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the difference to the counterparty. From time to time, we may sell future call options to obtain more favorable strike prices on swap or collar contracts.

- *Collars*. These instruments contain a fixed floor price (“put”) and ceiling price (“call”). If the market price exceeds the call strike price, we pay the difference between the market price and the strike price of the sold call to the counterparty. If the market price falls below the put strike price, we receive the difference between the market price and the strike price of the purchased put from the counterparty. If the market price is between the put and the call strike prices, no payments are due to or from either party.

- *Three-Way Collars*. Three-way collars consist of a traditional collar and our sale of an additional put option in exchange for more favorable strike prices on purchased put or sold call options.

- *Basis Swaps*. Our natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX. Therefore, we periodically use basis swaps to fix the differential between product prices at the following market locations relative to NYMEX: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, Eastern Gas South, TCO and Tetco M-2. Under these instruments, we receive the fixed price differential and pay the floating market price differential to the counterparty for the contracted volumes.

- *Interest Rate Swaps*. Interest rate swaps are used to fix interest rates on existing or anticipated floating rate indebtedness. The purpose of these instruments is to manage our existing or anticipated exposure to unfavorable interest rate changes. We pay a fixed interest rate and receive a floating interest rate from the counterparty subject to a floor of zero basis points.

All derivative instruments are recognized at their current fair value as either assets or liabilities on the consolidated balance sheets. Changes in the fair value of these derivative instruments are recorded in earnings as we have not elected hedge accounting for any of our derivative instruments.

The following table sets forth the average volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2021, the contracted weighted average natural gas prices, the contracted weighted average basis swap spreads and the estimated fair values:

		Weighted Average Prices ($/mmbtu)				
	Average Volume (mmbtu/d)	Swap Strike Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ (707,109)
2022	1,294,000	$ 2.70				
2023	780,000	$ 2.67				
2024	235,000	$ 2.61				
Collars:						4,220
2022	27,000		$ 5.78	$ 3.69		
2023	70,000		$ 4.32	$ 3.00		
Three-way collars:						(42,514)
2022	150,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(302,773)
2022	360,000		$ 2.99			
2023	370,000		$ 2.89			
2024	400,000		$ 2.84			
Basis swaps:						20,831
2022	758,000	$ (0.37)				
2023	190,000	$ (0.19)				
Total Estimated Fair Value						$ (1,027,345)

The following table sets forth the average volumes per day associated with our outstanding oil derivative instruments as of December 31, 2021, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbls/d)	Swap Strike Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ (29,508)
2022	5,000	$ 57.50		
2023	2,000	$ 62.78		
2024	1,000	$ 62.50		
Total Estimated Fair Value				$ (29,508)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2021, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbls/d)	Weighted Average Prices ($/bbl) Swap Strike Price	Fair Value ($ in thousands)
NGL:			
Swaps - Propane:			$ (19,654)
2022	4,000	$ 30.58	
2023	1,000	$ 31.50	
Total Estimated Fair Value			$ (19,654)

The following tables summarize the fair value of our derivative instruments on a gross basis, the effects of netting assets and liabilities for which the right of offset exists based on master netting agreements and the net amount presented on our consolidated balance sheets as of December 31, 2021 and 2020:

($ in thousands)	December 31, 2021		
Consolidated Balance Sheet Presentation	Fair Value, Gross	Amounts Netted on Balance Sheet	Fair Value, Net
Short-term derivative assets:			
Commodity derivatives	$ 47,869	$ (41,003)	$ 6,866
Total short-term derivative assets	$ 47,869	$ (41,003)	$ 6,866
Long-term derivative assets:			
Commodity derivatives	$ 23,896	$ (23,374)	$ 522
Total long-term derivative assets	$ 23,896	$ (23,374)	$ 522
Short-term derivative liabilities:			
Commodity derivatives	$ 689,876	$ (41,003)	$ 648,873
Total short-term derivative liabilities	$ 689,876	$ (41,003)	$ 648,873
Long-term derivative liabilities:			
Commodity derivatives	$ 458,396	$ (23,374)	$ 435,022
Total long-term derivative liabilities	$ 458,396	$ (23,374)	$ 435,022

($ in thousands)	December 31, 2020		
Consolidated Balance Sheet Presentation	Fair Value, Gross	Amounts Netted on Balance Sheet	Fair Value, Net
Short-term derivative assets:			
Commodity derivatives	$ 44,802	$ (36,600)	$ 8,202
Total short-term derivative assets	$ 44,802	$ (36,600)	$ 8,202
Long-term derivative assets:			
Commodity derivatives	$ 64,755	$ (62,354)	$ 2,401
Total long-term derivative assets	$ 64,755	$ (62,354)	$ 2,401
Short-term derivative liabilities:			
Commodity derivatives	$ 90,175	$ (36,600)	$ 53,575
Interest rate derivatives	569	—	569
Total short-term derivative liabilities	$ 90,744	$ (36,600)	$ 54,144
Long-term derivative liabilities:			
Commodity derivatives	$ 175,514	$ (62,354)	$ 113,160
Total long-term derivative liabilities	$ 175,514	$ (62,354)	$ 113,160

The following table summarizes the effects of derivative instruments on the consolidated statements of operations for the periods indicated:

($ in thousands)	Consolidated Statements of Operations Presentation	Year Ended December 31, 2021	2020	2019
Commodity derivatives	Commodity derivative (loss) gain	$ (1,743,892)	$ (19,167)	$ 441,139
Interest rate derivatives	Interest expense, net	$ (267)	$ (790)	$ —

6. Fair Value Measurements

We use a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2 – Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 – Unobservable inputs that reflect our own assumptions.

Fair Value on a Recurring Basis

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of December 31, 2021 and 2020. There were no transfers in or out of our Level 3 fair value measurements.

($ in thousands)	Fair value measurements at December 31, 2021: Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ —	$ 7,388	$ —	$ 7,388
Total	$ —	$ 7,388	$ —	$ 7,388
Liabilities:				
Commodity derivatives	$ —	$ 1,083,895	$ —	$ 1,083,895
Contingent payment right	—	—	85,223	85,223
Total	$ —	$ 1,083,895	$ 85,223	$ 1,169,118

($ in thousands)	Fair value measurements at December 31, 2020: Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ —	$ 10,603	$ —	$ 10,603
Total	$ —	$ 10,603	$ —	$ 10,603
Liabilities:				
Commodity derivatives	$ —	$ 166,735	$ —	$ 166,735
Interest rate derivatives	—	569	—	569
Contingent payment right	—	—	65,302	65,302
Total	$ —	$ 167,304	$ 65,302	$ 232,606

Derivatives. We estimate the fair value of our commodity and interest rate derivatives using models that utilize market-based parameters and are therefore classified as Level 2 fair value measurements. The fair value of our commodity swaps, collars and options are based on standard industry income approach models that use significant observable inputs including, but not limited to, forward curves, discount rates, nonperformance risk and volatilities. We estimate the fair value of our interest rate swaps using a discounted cash flow model utilizing the contracted notional amounts, active market-quoted LIBOR yield curves and the applicable credit-adjusted risk-free rate yield curve. See Note 5 for further information regarding our derivative instruments.

Contingent Payment Right. The 2027 Notes contain a contingent payment right which entitles the holders to receive a fixed amount of cash or equity that, as of December 31, 2021, ranged from 35% to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if a Triggering Event occurs. See Note 4, *2027 Notes*, for further information regarding the contingent payment right. The contingent payment right is required to be bifurcated and accounted for as a liability at fair value. The fair value of the contingent payment right is based on unobservable inputs and is therefore classified as Level 3.

The fair value of the contingent payment right was determined using a "with" and "without" analysis, which compares the value of the 2027 Notes including the contingent payment right to the value of an otherwise identical bond that omits the contingent payment right feature by comparing the discounted cash flows. The significant unobservable inputs used to estimate the fair value of the contingent payment right include the probability of a Triggering Event occurring prior to maturity and the discount rate used in the discounted cash flow analysis. Changes in these inputs impact the fair value measurement of the contingent payment right. For example, an increase or decrease in the probability of a Triggering Event occurring would increase or decrease, respectively, the fair value of the contingent payment right. Additionally, an increase or decrease in the discount rate would decrease or increase, respectively, the fair value of the contingent payment right. The contingent payment right is presented as part of other long-term liabilities on the consolidated balance sheets. Changes in its fair value are presented as a change in fair value of the contingent payment right on the consolidated statements of operations.

The following table presents quantitative information about Level 3 inputs used in the fair value measurement of the contingent payment right:

	December 31,	
	2021	2020
Probability of a Triggering Event prior to maturity	70%	70%
Discount rate	6.5%	12.4%

The following table presents a reconciliation of changes in the fair value of the contingent payment right, which is presented as an other long-term liability on the consolidated balance sheets:

	December 31,	
($ in thousands)	2021	2020
Balance, beginning of period	$ 65,302	$ —
Change due to issuance of debt	—	58,784
Change in fair value	19,921	6,518
Balance, end of period	$ 85,223	$ 65,302

Fair Value of Debt

The carrying amounts and estimated fair values of our debt instruments as of December 31, 2021 and 2020 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 4 for further information regarding our debt.

	December 31,			
	2021		2020	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 495,000	$ 495,000	$ 953,000	$ 953,000
2025 Second Lien Term Loans	530,841	599,306	527,108	606,179
2026 Notes	589,644	612,663	587,925	576,655
2027 Notes	283,795	465,639	277,006	387,863
2028 Notes	295,375	312,803	294,857	299,683
2029 Notes	393,593	384,190	—	—
2022 Notes	—	—	67,486	70,477
Convertible Notes	—	—	12,498	12,665
Total	$ 2,588,248	$ 2,869,601	$ 2,719,880	$ 2,906,522

7. Stock-Based Compensation

In July 2020, our Parent established a long-term incentive plan (the "Plan") in order to further our growth and success. Under the Plan, the board of managers of our Parent may, among other things, grant time-vested restricted stock units ("Time-Vested RSUs") and performance-vested restricted stock units ("Performance-Vested RSUs," and together with the Time-Vested RSUs, the "RSUs") to certain of our employees and certain managers of the board of our Parent. Under the Plan, 360.2 million common units of the Parent were reserved for issuance. The RSUs contain distribution equivalent rights, which entitle participants to cash distributions on unvested RSUs if and to the extent holders of common units receive cash distributions. As of December 31, 2021, approximately 50.4 million common units were available for future grants under the Plan.

Stock-based compensation was $3.6 million and $1.8 million for the years ended December 31, 2021 and 2020, respectively, and is presented as part of general and administrative expenses on the consolidated statements of operations. We account for forfeitures during the period in which they occur by reversing the expense previously recognized for such awards.

Time-Vested Restricted Stock Units

Time-Vested RSUs are accounted for as equity awards, and comprised 50% of the RSUs granted under a participant's Plan award. Vesting is subject to a service condition which is generally satisfied over five years in one-year tranches. Stock-based compensation related to the Time-Vested RSUs is measured based on the fair value on the date of grant using appropriate valuation techniques and is recognized on a straight-line basis over the requisite service period. Time-Vested RSUs are subject to an accelerated vesting schedule upon certain events which are generally outside of the control of the participant.

A summary of Time-Vested RSU activity for the year ended December 31, 2021 is as follows:

(in thousands, except weighted average fair value)	Number of Unvested Time-Vested RSUs	Weighted Average Grant Date Fair Value
Unvested Time-Vested RSUs as of December 31, 2020	159,785	$ 0.10
2021 Grants	10,289	$ 0.17
2021 Forfeitures	(7,264)	$ 0.10
2021 Vestings	(32,204)	$ 0.10
Unvested Time-Vested RSUs as of December 31, 2021	130,606	$ 0.11

As of December 31, 2021, there was $11.6 million of unrecognized compensation costs related to unvested Time-Vested RSUs. The unamortized compensation costs are expected to be recognized over a weighted average period of approximately 3.5 years.

Performance-Vested Restricted Stock Units

Performance-Vested RSUs are accounted for as liability awards and comprised 50% of the RSUs granted under a participant's Plan award. Vesting is subject to a performance condition which is generally satisfied upon the occurrence of a qualifying liquidity event ("QLE") as defined in the Plan. Upon each QLE, participants are generally entitled to cash payments, or upon a QLE by which our Parent becomes a publicly held corporation, common stock in such public entity. The ultimate settlement of Performance-Vested RSUs would be partially or fully offset to the extent cash awards were previously received as part of the Plan (the "Cash Award Offset"), and any such Performance-Vested RSUs for which the Cash Award Offset has been applied are forfeited. Cash Award Offset payments are triggered upon us achieving certain leverage metrics which would result in cash payments ranging from 2.5% to 5.0% of annual free cash flow as defined in the Plan, and therefore, are accrued when determined probable. Stock-based compensation related to the Performance-Vested RSUs is recognized at fair value using appropriate valuation techniques on such date it becomes probable that the performance condition will be achieved, and is remeasured each period at fair value through settlement. Performance-Vested RSUs are subject to an accelerated vesting schedule upon certain events which are generally outside of the control of the participant, and are subject to expiration.

(in thousands, except weighted average fair value)	Number of Unvested Performance-Vested RSUs	Weighted Average Grant Date Fair Value	
Unvested Performance-Vested RSUs as of December 31, 2020	159,785	$	0.10
2021 Grants	10,289	$	0.17
2021 Forfeitures	(8,985)	$	0.10
2021 Vestings	—	$	—
Unvested Performance-Vested RSUs as of December 31, 2021	161,089	$	0.10

8. Related Party Transactions

Natural Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements

In the normal course of our business, we have entered into certain business relationships with entities in which EMG or First Reserve have control or significant influence through their equity investments. These relationships include agreements for the sale of our NGL production and the gathering, processing and transportation of our natural gas and NGL production.

The following table summarizes the expenses incurred and the revenues realized with our related parties for the periods indicated:

($ in thousands)	Year Ended December 31,					
Consolidated Statements of Operations Presentation	**2021**		**2020**		**2019**	
NGL revenues	$	109,727	$	66,980	$	104,783
Gathering, processing and transportation expenses	$	620,272	$	623,656	$	607,785

The following table summarizes the accounts receivable due from these purchasers and the amounts due to companies associated with these agreements for the periods indicated:

($ in thousands)	December 31,			
Consolidated Balance Sheets Presentation	**2021**		**2020**	
Accounts receivable - natural gas, oil and NGL sales	$	10,091	$	9,466
Other current liabilities	$	96,469	$	96,634

For information regarding the credit support requirements due to certain related parties, see Note 10, *Pipeline Commitments*.

Long-Term Debt

In connection with the Exchange, we issued $12.0 million in aggregate principal amount of 2025 Second Lien Term Loans and $8.6 million in aggregate principal amount of 2027 Notes to certain of our Parent's existing equity holders and their designated affiliates. As of both December 31, 2021 and 2020, $8.6 million in aggregate principal amount of 2025 Second Lien Term Loans and $0.3 million in aggregate principal amount of 2027 Notes were held by certain related parties.

9. Leases

We enter into certain agreements for tangible assets, real estate and easements to support our operations. To the extent that we determine an arrangement represents a lease in accordance with ASC 842, we classify that lease as an operating or financing lease. The following table summarizes our ROU assets and lease liabilities on the consolidated balance sheets as of December 31, 2021 and 2020:

($ in thousands)	Consolidated Balance Sheet Presentation	December 31, 2021	December 31, 2020
Operating leases:			
ROU assets, net	Other long-term assets	$ 35,132	$ 18,328
Short-term lease liabilities	Other current liabilities	$ 25,127	$ 11,944
Long-term lease liabilities	Other long-term liabilities	9,769	6,033
Total operating lease liabilities		$ 34,896	$ 17,977
Financing leases:			
ROU assets, net	Property and equipment, net	$ 1,557	$ 1,574
Short-term lease liabilities	Other current liabilities	$ 686	$ 588
Long-term lease liabilities	Other long-term liabilities	469	551
Total financing lease liabilities		$ 1,155	$ 1,139

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners for the periods presented:

($ in thousands)	Consolidated Financial Statement Presentation	Year Ended December 31, 2021	2020	2019
Operating lease cost:				
Operating lease cost	General and administrative expense	$ 1,881	$ 1,931	$ 1,931
Operating lease cost	Lease operating expense	5,715	3,014	1,659
Operating lease cost	Natural gas and oil properties	11,285	7,450	24,629
Total operating lease cost		$ 18,881	$ 12,395	$ 28,219
Financing lease cost:				
Amortization of ROU assets	DD&A	$ 1,024	$ 697	$ 239
Interest on lease liabilities	Interest expense	43	46	21
Total financing lease cost		$ 1,067	$ 743	$ 260
Short-term lease cost:				
Short-term lease cost	Lease operating expense	$ 4,765	$ 4,608	$ 3,146
Short-term lease cost	Natural gas and oil properties	14,856	16,624	19,271
Total short-term lease cost		$ 19,621	$ 21,232	$ 22,417
Variable lease cost	Natural gas and oil properties	$ 2,532	$ 2,525	$ 7,082

Additional information for our operating and financing leases is summarized below:

	Year Ended December 31,					
	2021		2020		2019	
($ in thousands)	Operating	Financing	Operating	Financing	Operating	Financing
Cash outflows for lease liabilities:						
Operating cash flows	$ 7,605	$ 43	$ 4,887	$ 47	$ 3,649	$ 22
Investing cash flows	$ 11,095	$ —	$ 7,666	$ —	$ 24,603	$ —
Financing cash flows	$ —	$ 998	$ —	$ 814	$ —	$ 556
Non-cash activities:						
ROU assets obtained in exchange for lease liabilities	$ 35,100	$ 1,031	$ 18,207	$ 1,132	$ 16,164	$ 1,380

	December 31, 2021		December 31, 2020	
	Operating	Financing	Operating	Financing
Weighted average remaining lease term (in years)	1.7	1.9	1.8	2.0
Weighted average discount rate	2.6 %	3.1 %	2.8 %	3.8 %

The following table presents our maturity analysis as of December 31, 2021 for future lease expirations. We do not have any lease maturities after 2025.

	December 31, 2021	
($ in thousands)	Operating	Financing
2022	$ 25,697	$ 709
2023	6,618	361
2024	2,901	116
2025	448	—
Total lease payments	35,664	1,186
Less: imputed interest	(768)	(31)
Present value of lease liabilities	$ 34,896	$ 1,155

10. Commitments and Contingencies

Litigation Matters

We are periodically involved in litigation and regulatory proceedings, investigations and disputes, including matters relating to commercial transactions, operations, landowner disputes, royalty claims, property damage claims, contract actions and environmental, health and safety matters. We may also periodically be involved in disputes with our midstream counterparties, some of which are related parties as discussed in Note 8, including disputes arising due to the overlapping nature of dedication provisions, ownership and contractual interests in the Utica Shale. A liability is recognized for any contingency that is probable and reasonably estimable. We continually assess the likelihood of adverse judgments or outcomes in these matters, as well as potential ranges of possible losses, based on a careful analysis of each matter and, if necessary, with the assistance of outside legal counsel and other experts. We will continue to monitor the impact that litigation could have on us and will assess the impact of future events. Legal defense costs are accounted for in the period the costs are incurred.

We are defending against certain pending claims, have resolved a number of claims through negotiated settlements and have prevailed in various other lawsuits. Based on management's current assessment, we believe no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

For all such claims, disputes and threatened or pending litigation, we have accrued $15.0 million as of both December 31, 2021 and 2020, which is presented as part of other current liabilities on the consolidated balance sheets. The final resolution of such matters could differ materially from management's estimates.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental matters, such as the Comprehensive Environmental Response, Compensation and Liability Act and similar statutes. From time to time, we are party to various environmental and regulatory proceedings in the ordinary course of business. Management does not believe the results of these environmental proceedings, individually or in the aggregate, will have a material adverse effect on us.

Pipeline Commitments

We have entered into certain pipeline capacity commitments with various counterparties in order to facilitate the delivery of our production to market and reduce the likelihood of possible production curtailments that may arise due to limited capacity. Through these contracts, we are committed to transport minimum daily natural gas volumes at negotiated rates or pay for any deficiencies. The table below presents our undiscounted pipeline commitments that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2021 and represents the gross amounts we are committed to pay; however, working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs.

($ in thousands)	Pipeline Commitments
2022	$ 662,606
2023	663,401
2024	655,639
2025	646,668
2026	642,897
2027 and Thereafter	4,838,342
Total	$ 8,109,553

To satisfy credit support requirements for these commitments, $169.2 million in letters of credit and $258.7 million in surety bonds were issued by us or on our behalf to certain transportation providers as of December 31, 2021. Our credit support includes support provided to certain related parties, which, as of December 31, 2021, included $121.3 million in letters of credit and $192.6 million in surety bonds. For information regarding certain other transactions with related parties, see Note 8.

11. Other Current Liabilities

Our other current liabilities consisted of the following as of the dates indicated:

	December 31,	
($ in thousands)	2021	2020
Gathering, processing and transportation expense accrual	$ 130,677	$ 130,058
Revenues and royalties due others	196,966	84,142
Drilling and completion cost accrual	73,851	48,922
Taxes other than income accrual	27,364	29,850
Operating and financing leases	25,813	12,532
Other	63,282	48,665
Total Other Current Liabilities	$ 517,953	$ 354,169

12. Supplemental Information on Natural Gas, Oil and NGL Producing Activities (Unaudited)

The following disclosures provide supplemental unaudited information regarding our natural gas, oil and NGL activities, which are entirely within the United States:

Capitalized costs related to our natural gas, oil and NGL producing activities are summarized as follows:

	December 31,	
($ in thousands)	2021	2020
Proved	$ 8,560,861	$ 7,752,572
Unproved	823,018	1,038,298
Total	9,383,879	8,790,870
Accumulated depreciation, depletion and amortization	(3,204,967)	(2,610,024)
Net Capitalized Costs	$ 6,178,912	$ 6,180,846

Costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized in the table below:

	Year Ended December 31,		
($ in thousands)	2021	2020	2019
Acquisition costs of properties:			
Proved properties	$ 2,624	$ 4,811	$ 18,075
Unproved properties	91,801	121,211	218,337
Total property acquisition costs	94,425	126,022	236,412
Exploration costs	3,049	3,926	8,098
Development costs	577,805	531,066	1,058,908
Total	$ 675,279	$ 661,014	$ 1,303,418

Results of Operations from Natural Gas, Oil and NGL Producing Activities

The results of operations included below consist of revenues and expenses directly associated with our natural gas, oil and NGL producing activities. These results do not include the effects of commodity derivatives or any interest expense or indirect general and administrative costs, and therefore, are not necessarily indicative of the net operating results of our natural gas, oil and NGL operations.

	Year Ended December 31,		
($ in thousands)	2021	2020	2019
Revenues, excluding the effects of commodity derivatives	$ 2,939,957	$ 1,515,541	$ 1,979,259
Lease operating expenses	(90,719)	(77,521)	(71,968)
Gathering, processing and transportation expenses	(936,134)	(919,986)	(856,126)
Taxes other than income	(38,988)	(37,495)	(34,167)
Exploration expenses	(83,367)	(104,230)	(124,477)
Natural gas and oil depreciation, depletion and amortization	(595,481)	(733,450)	(702,414)
Results of Operations	$ 1,195,268	$ (357,141)	$ 190,107

Natural Gas, Oil and NGL Reserves

Proved reserves are estimated volumes of natural gas, oil and NGL that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells, reasonably certain of containing proved reserves and scheduled to begin drilling within five years under our development plan. Our development plans are subject to uncertainties and variables, including the availability of capital, future natural gas, oil and NGL prices, cash flows from operations, future drilling costs, demand for natural gas, oil and NGL and other economic factors. Our net quantities of proved reserves include our royalty interests and exclude any interests owned by others.

Our proved natural gas, oil and NGL reserves for the year ended December 31, 2021 were prepared by our internal reserve engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI") utilizing data we compiled. Proved reserves estimates for the year ended December 31, 2020 were prepared by NSAI, where their type curves were used as the basis for their reserves projections. Proved reserves estimates for the year ended 2019 were prepared by Software Integrated Solutions (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation.

Estimating quantities of proved natural gas, oil and NGL reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data and estimates are revised, as warranted by additional performance data. The information provided below related to our natural gas, oil and NGL reserves is presented in accordance with regulations prescribed by the SEC.

Subsequent to December 31, 2021, there have been no major discoveries, favorable or otherwise, that are considered to have caused a significant change in our estimated proved reserves at December 31, 2021. The following table sets forth our proved reserves during the periods indicated, all of which are located within the Utica Shale:

	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)[(a)]
Proved Reserves at December 31, 2018	6,736,473	42,444	104,105	7,615,763
Extensions, discoveries and other additions	2,609,827	13,967	48,185	2,982,736
Revisions	(565,152)	(3,358)	(7,589)	(630,831)
Purchases of reserves	12,407	—	—	12,407
Sales of reserves	(9,247)	—	—	(9,247)
Production	(638,243)	(4,794)	(8,685)	(719,113)
Proved Reserves at December 31, 2019	8,146,065	48,259	136,016	9,251,715
Extensions, discoveries and other additions	822,859	4,644	9,445	907,393
Revisions	(248,908)	(5,999)	(25,796)	(439,680)
Production	(646,982)	(4,291)	(9,304)	(728,553)
Proved Reserves at December 31, 2020	8,073,034	42,613	110,361	8,990,875
Extensions, discoveries and other additions	735,688	6,707	15,384	868,234
Revisions	46,756	1,502	5,349	87,862
Production	(645,752)	(3,110)	(7,012)	(706,484)
Proved Reserves at December 31, 2021	8,209,726	47,712	124,082	9,240,487
Proved developed reserves:				
December 31, 2019	3,443,414	16,000	61,770	3,910,032
December 31, 2020	3,830,924	16,273	57,831	4,275,548
December 31, 2021	4,493,267	14,587	51,594	4,890,355
Proved undeveloped reserves:				
December 31, 2019	4,702,651	32,259	74,246	5,341,683
December 31, 2020	4,242,110	26,340	52,530	4,715,327
December 31, 2021	3,716,459	33,124	72,488	4,350,132

(a) Oil and NGL are converted to mcfe at the rate of one bbl equals six mcf based upon the approximate relative energy content of oil and NGL to natural gas, which is not necessarily indicative of the relationship of oil and NGL to natural gas prices.

During the year ended December 31, 2021, we added approximately 868.2 bcfe in proved reserves through the continued development of our Utica Shale acreage. Upward revisions of previous estimates of approximately 87.9 bcfe were primarily driven by SEC price improvements which resulted in an increase of 176.8 bcfe, partially offset by a decrease of 88.9 bcfe due to the removal of

PUDs where it was determined development would occur outside of our five-year development plan, net of positive performance revisions and development plan optimization. As of December 31, 2021, all proved undeveloped locations were in accordance with the SEC five-year rule. The average adjusted prices used to calculate reserves at December 31, 2021 were $3.56 per mcf for natural gas, $59.39 per bbl for oil and $31.89 per bbl of NGL utilizing a benchmark of $3.60 per mmbtu of natural gas and $66.55 per bbl of oil and condensate.

During the year ended December 31, 2020, we added approximately 907.4 bcfe in proved reserves through the continued development of our Utica Shale acreage. Downward revisions of previous estimates of approximately 439.7 bcfe included revisions of 258.6 bcfe resulting from removing PUDs where it was determined development would occur outside of our five-year development plan and other revisions to proved reserves estimates of 181.1 bcfe primarily due to type curve updates. As of December 31, 2020, all proved undeveloped locations were in accordance with the SEC five year rule. The average adjusted prices used to calculate reserves at December 31, 2020 were $1.89 per mcf for natural gas, $32.40 per bbl for oil and $12.36 per bbl of NGL utilizing a benchmark of $1.99 per mmbtu of natural gas and $39.54 per bbl of oil and condensate.

During the year ended December 31, 2019, we added approximately 2.983 tcfe in proved reserves through the continued development of our Utica Shale acreage. Revisions of previous estimates included downward revisions of 164.2 bcfe due to lower commodity prices and downward revisions of 466.6 bcfe primarily from removing PUDs where it was determined development would occur outside of our five-year development plan and type curve updates. We added proved reserves through acquisitions of 12.4 bcfe. As of December 31, 2019, all proved undeveloped locations were in accordance with the SEC five year rule. The average adjusted prices used to calculate reserves at December 31, 2019 were $2.55 per mcf for natural gas, $49.32 per bbl for oil and $17.52 per bbl of NGL utilizing a benchmark of $2.58 per mmbtu of natural gas and $55.85 per bbl of oil and condensate.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves

ASC 932, *Extractive Activities - Oil and Gas*, prescribes guidelines for computing a standardized measure of future net cash flows and changes therein related to proved reserves. We have followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2021, 2020 and 2019 were determined by applying the unweighted arithmetic average of the prices on the first day of each month for the 12 months of the year and year-end costs to the estimated quantities of natural gas, oil and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic condition applied for that year. We are a disregarded entity for income tax purposes, and therefore, we have estimated no future income tax expense. The resulting future net cash flows are reduced to the present value amount by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the FASB and do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following table sets forth our standardized measure of future net cash flows from our proved natural gas, oil and NGL reserves:

	December 31,		
($ in thousands)	2021	2020	2019
Future cash inflows	$ 36,002,574	$ 18,007,344	$ 25,534,390
Future production costs	(15,079,666)	(13,243,886)	(14,026,060)
Future development costs	(1,850,383)	(1,975,980)	(2,887,918)
Future net cash flows	19,072,525	2,787,478	8,620,412
Discount to present value at 10% annual rate	(9,936,965)	(1,522,378)	(4,662,760)
Standardized Measure of Discounted Future Net Cash Flows	$ 9,135,560	$ 1,265,100	$ 3,957,652

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves

The following table sets forth the changes in our standardized measure of future net cash flows from our proved natural gas, oil and NGL reserves:

	Year Ended December 31,		
($ in thousands)	2021	2020	2019
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Period	$ 1,265,100	$ 3,957,652	$ 5,950,580
Sales of natural gas, oil and NGL produced, net of production costs	(1,874,116)	(479,630)	(1,016,360)
Net changes in prices and production costs	9,049,798	(3,519,899)	(2,589,311)
Extensions and discoveries, net of production and development costs	962,303	87,268	1,240,076
Changes in future development costs	(68,401)	455,834	(74,440)
Previously estimated development costs incurred during the year	310,194	545,553	387,391
Revisions of previous quantity estimates	58,031	(133,195)	(473,097)
Purchase of reserves	—	—	19,718
Sales of reserves	—	—	(2,262)
Accretion of discount	126,510	395,765	595,058
Changes in production rates and other	(693,859)	(44,248)	(79,701)
Standardized Measure of Discounted Future Net Cash Flows, End of Period	$ 9,135,560	$ 1,265,100	$ 3,957,652